NEXTera ENERGY SEABROOK

November 15, 2010

SBK-L-10192

Docket No. 50-443

U.S. Nuclear Regulatory Commission
Attention: Document Control Desk
One White Flint North
11555 Rockville Pike
Rockville, MD 20852

Seabrook Station
Supplement 2 to the NextEra Energy Seabrook, LLC
Seabrook Station License Renewal Application

References:

1. NextEra Energy Seabrook, LLC letter SBK-L-10077, "Seabrook Station Application for Renewed Operating License" May 25, 2010 (Accession Number ML101590099)

2. NextEra Energy Seabrook, LLC letter SBK-L-10179, "Supplement to the NextEra Energy Seabrook, LLC, Seabrook Station License Renewal Application", October 29, 2010

By Reference 1, NextEra Energy Seabrook, LLC submitted an application for a renewed Facility Operating License for Seabrook Station Unit No. 1. In Reference 2, NextEra Energy Seabrook, LLC submitted changes to incorporate significant industry operating experience into the Buried Piping and Tanks Inspection Program and the Inaccessible Medium Voltage Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Programs.

In this Supplement are: 1) revised LRA Chapter 3 tables associated with the Buried Piping and Tanks Inspection Program submitted in NextEra Energy Seabrook, LLC letter SBK-L-10179, October 29, 2010, 2) addition of a Protective Coating Monitoring and Maintenance Program (B.2.1.38) and 3) various clarifications to the LRA.

The changes are provided in Enclosures 1 through 5 to this letter. The changes are explained, and where appropriate to facilitate understanding, portions of the LRA are repeated with the change highlighted by strikethroughs for deleted text and bolded italics for inserted text. In some instances the entire text of a section has been replaced. In these cases a note is included in the introduction indicating the replacement of the entire text of the section.

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Commitment numbers 10, 11, 13, 22, 23 and 25 of the License Renewal Commitment List are modified to clarify the commitment schedule and new commitments 46 through 49 are added. There are no other new or revised regulatory commitments contained in this letter. Enclosure 6 provides a revised LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List, updated to reflect the license renewal commitment changes made in NextEra Energy Seabrook correspondence to date.

If there are any technical questions or additional information needed, please contact Mr. Richard R. Cliche, License Renewal Project Manager, at (603) 773-7003.

If you have any questions regarding this correspondence, please contact Mr. Michael O'Keefe, Licensing Manger, at (603) 773-7745.

Sincerely,

NextEra Energy Seabrook, LLC

Paul O. Freeman
Site Vice President

Enclosures:

Enclosure 1- Changes to the Seabrook Station License Renewal Application Associated with Chapter 2 – Scoping and Screening Methodology

Enclosure 2- Changes to the Seabrook Station License Renewal Application Associated with Chapter 3 - Aging Management Review Results

Enclosure 3- Changes to the Seabrook Station License Renewal Application Associated with Chapter 4 – Time Limited Aging Analyses

Enclosure 4- Changes to the Seabrook Station License Renewal Application Associated with Appendix A – Updated UFSAR Supplement, and Appendix B – Aging Management Programs

Enclosure 5- Changes to the Seabrook Station License Renewal Application Associated with the Protective Coating Monitoring and Maintenance Program B.2.1.38

Enclosure 6- LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List, updated to reflect the license renewal commitment changes made in NextEra Seabrook correspondence to date.

cc:

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NEXTera ENERGY SEABROOK

I, Paul O. Freeman, Site Vice President of NextEra Energy Seabrook, LLC hereby affirm that the information and statements contained within are based on facts and circumstances which are true and accurate to the best of my knowledge and belief.

Sworn and Subscribed

Before me this

15 day of November, 2010

Paul O. Freeman
Site Vice President

Notary Public

MICHAEL D. O'KEEFE
MY COMMISSION EXPIRES FEB. 13, 2013
NOTARY PUBLIC
NEW HAMPSHIRE

Enclosure 1 to SBK-L-10192

Changes to the

Seabrook Station License Renewal Application

Associated with

Chapter 2 – Scoping and Screening Methodology

Introduction

For clarification, line items for thermal insulation are being added to the Seabrook Station License Renewal Application.

Description of Changes

CHANGES TO SECTION 2.4

1. Revise the first paragraph of LRA Chapter 2, Section 2.4.6 (page 2.4-28) as follows:

   Supports at Seabrook Station includes ASME & NON-ASME pipe restraints/supports, jet impingement barriers/shields (e.g., High Energy Line Break barriers), pipe whip restraints, supports for Tube Track, instrument tubing, miscellaneous mechanical equipment, electrical raceways and conduit, HVAC ducts, racks, panels, cabinets, enclosures for electrical equipment, junction boxes, platforms, grout under baseplates and fasteners for support or equipment anchorage and other miscellaneous structures, instrument and battery racks, support base plate pads (silicone caulking, ethafoam, elastomer, teflon and sealant compounds)***, thermal insulation and reflective metallic insulation jacketing*** for components and equipment that are in scope for license renewal or are located within structures containing safety related components.

2. Revise the fourth paragraph of LRA Chapter 2, Section 2.4.6 (page 2.4-29) to add final bullet:

   - ***Thermal insulation.***

3. Revise LRA Chapter 2, Table 2.4-6 (page 2.4-31) to add the following line item:

THERMAL INSULATION IN AIR – INDOOR UNCONTROLLED	*Insulates*

Enclosure 2 to SBK-L-10192

Changes to the

Seabrook Station License Renewal Application

Associated with

Chapter 3 – Aging Management Review Results

Description of Changes

CHANGES TO SECTION 3.1

1. Table 3.1.2-2 is a summary of the aging effects for the Reactor Vessel. On page 3.1-70, the fifth line item on the page describes aging management for cracking of the Nickel Alloy Control Rod Drive Pressure Housings. The aging management programs listed in the application includes Section XI, Water Chemistry and Nickel Alloy Nozzles and Penetrations. The Nickel Alloy Nozzles and Penetrations program does not age manage the Control Rod Drive Pressure Housings.

   a. Revise the fifth row in Table 3.1.2-2 on page 3.1-70 as follows:

Control Rod Drive Pressure Housing	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection Subsections IWB IWC and IWD Program Water Chemistry Program ~~Nickel Alloy Nozzles and Penetrations program~~	IV.A2-11 (R-76)	3.1.1-34	A,4 A,4 A

   b Add the following new Plant Specific Note to Table 3.1.2-2 on page 3.1-81:

      4 NUREG-1801 Rev 1 Provides for a commitment in the FSAR supplement to implement applicable bulletins and letters and staff accepted industry guidelines, which Seabrook Station met by the Nickel Alloy Nozzles and Penetrations Program as providing aging management for PWSCC for this component. This program should not be listed as an applicable aging management program because its not a penetration or nozzle.

   c. Revise line item 3.1.1-34 on page 3.1-28 as follows;

3.1.1-34	Stainless steel and nickel alloy reactor control rod drive head penetration pressure housings	Cracking due to stress corrosion cracking and primary water stress corrosion cracking	Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines.	No, but licensee commitment needs to be confirmed	Consistent with NUREG-1801. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, B.2.1.1, and the Water Chemistry Program, B.2.1.2, will be used to manage cracking due to stress corrosion cracking in the stainless steel canopy seal pressure housing and cracking due to primary water stress corrosion cracking in the nickel alloy control rod drive pressure housing exposed to reactor coolant in the Reactor Vessel. See Subsection 3.1.2.2.16.1. ***For the nickel alloy component, the commitment is not applicable.***

d. After the second paragraph of Section 3.1.2.2.16.1 "Cracking due to Stress Corrosion Cracking and Primary Stress Corrosion Cracking discussion on page 3.1-17 add the following:

For the nickel alloy component, the commitment is not applicable.

2. Table 3.1.2-2 is a summary of aging management for the Reactor Vessel. On page 3.1-78, the first line on the page describes aging management for cracking of the Reactor Vessel Primary Inlet and Outlet Nozzle Welds. The aging management programs listed in the application includes ASME Section XI and Water Chemistry but does not include Nickel Alloy Nozzles and Penetrations. The table line item needs to be revised to add the Nickel Alloy Nozzles and Penetrations Program as an aging management program.

    a. Revise line item 3.1.1-69 on page 3.1-36 as follows:

3.1.1-69	Stainless steel, nickel alloy safety injection nozzles, safe ends, and associated welds and buttering exposed to reactor coolant	Cracking due to stress corrosion cracking, primary water stress corrosion cracking	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Consistent with NUREG-1801. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, B.2.1.1, the Water Chemistry Program, B.2.1.2, ***and the Nickel Alloy Nozzles and Penetrations Program, B.2.2.3,*** will be used to manage cracking due to stress corrosion cracking in the stainless steel vessel nozzle safe ends and cracking due to primary water stress corrosion cracking in the nickel alloy nozzle welds exposed to reactor coolant in the Reactor Vessel.

    b. Revise the first row in Table 3.1.2-2 on page 3.1-78 as follows:

Reactor Vessel Primary Inlet and Outlet Nozzle Welds	Pressure Boundary	Nickel Alloy	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection Subsections IWB IWC and IWD Program Water Chemistry Program ***Nickel Alloy Nozzles and Penetrations Program***	IV.A2-15 (R-83)	3.1.1-69	A A ***E,3***

c. Add the following new Plant Specific Note to Table 3.1.2-2 on page 3.1-81:

3	***NUREG-1801 Rev 1 does not include the Nickel Alloy Nozzles and Penetrations Program for aging management of PWSCC for these components. This program should be recognized as an appropriate aging management program for this component-material-environment combination.***

3. Table 3.1.2-4 for Steam Generator for the component type "Steam Generator Primary Nozzle Weld" lists the material as Nickel Alloy and shows Nickel Alloy Nozzles and Penetrations as the aging management program. The weld material should have been listed as stainless steel.

   The following LRA changes need to be made to reflect the change in the weld material from Nickel Alloy to stainless steel;

   a. Revise the Section 3.1.2.2.13 "Cracking due to Primary Water Stress Corrosion Cracking (PWSCC)" discussion on page 3.1-16 as follows:

      Seabrook Station will implement the ASME Section XI Inservice Inspection , Subsections IWB, IWC, and IWD Program, B.2.1.1, the Nickel-Alloy Nozzles and Penetrations Program, B.2.2.3, and the Water Chemistry Program, B.2.1.2, to manage the aging effects of cracking due to primary water stress corrosion cracking in nickel alloy components in the Reactor Coolant System, in the nickel alloy bottom instrument tube, core support pads/core guide lugs in the Reactor Vessel, and the nickel alloy ~~steam generator primary nozzle weld in the~~ Steam Generator ***channel head drain pipe.*** The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, the Nickel-Alloy Nozzles and Penetrations Program, and the Water Chemistry Program are described in Appendix B.

   b. Add the following bullet to Section 3.1.2.1.4 on page 3.1-7 under "Aging Management Programs" after the Flow Accelerated Corrosion Program:

      - ***Nickel Alloy Nozzles and Penetrations Program (B.2.2.3)***

c. Revise line item 3.1.1-31 on page 3.1-27 as follows:

3.1.1-31	Nickel alloy and steel with nickel-alloy cladding piping, piping component, piping elements, penetrations, nozzles, safe ends, and welds (other than reactor vessel head); pressurizer heater sheaths, sleeves, diaphragm plate, manways and flanges; core support pads/core guide lugs	Cracking due to primary water stress corrosion cracking	Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry and for nickel alloy, comply with applicable NRC Orders and provide a commitment in the FSAR supplement to implement applicable (1) Bulletins and Generic Letters and (2) staff-accepted industry guidelines	No, but licensee commitment needs to be confirmed	Consistent with NUREG-1801. The ASME Section XI Inservice Inspection Subsections IWB, IWC, and IWD Program, B.2.1.1, the Nickel-Alloy Nozzles and Penetrations Program, B.2.2.3, and the Water Chemistry Program, B.2.1.2, will be used to manage cracking due to primary water stress corrosion cracking in nickel alloy components in the Reactor Coolant system, in the nickel alloy bottom instrument tube and core support pads/core guide lugs in the Reactor Vessel, and the nickel alloy Steam Generator ~~primary nozzle weld in the Steam Generator~~ ***channel head drain pipe.*** See Subsection 3.1.2.2.13.

d. Revise line item 3.3.3-68 on page 3.1-36 as follows;

3.1.1-68	Stainless steel, steel with stainless steel cladding Class 1 piping, fittings, pump casings, valve bodies, nozzles, safe ends, manways, flanges, CRD housing; pressurizer heater sheaths, sleeves, diaphragm plate; pressurizer relief tank components, reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings	Cracking due to stress corrosion cracking	Inservice Inspection (IWB, IWC, and IWD), and Water Chemistry	No	Components in the Chemical and Volume Control, Residual Heat Removal, and Safety Injection systems have been aligned to this line item based on material, environment, and aging effect. Consistent with NUREG-1801. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, B.2.1.1, and the Water Chemistry Program, B.2.1.2, will be used to manage cracking due to stress corrosion cracking in the stainless steel Class 1 piping components in the Chemical and Volume Control, Reactor Coolant, Residual Heat Removal, and Safety Injection systems and the pressurizer diaphragm plate, pressurizer heater sleeves, reactor coolant system cold leg, hot leg, surge line, and spray line components in the Reactor Coolant system exposed to reactor coolant. Consistent with NUREG-1801. The ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD Program, B.2.1.1, and the Water Chemistry Program, B.2.1.2, will be used to manage cracking due to stress corrosion cracking in the steel with stainless steel cladding in Steam Generator lower head, Steam Generator primary manway, Steam Generator primary nozzle, and the stainless steel Steam Generator primary nozzle safe end, ***Steam Generator primary nozzle weld,*** and Steam Generator ***channel head*** drain line ***coupling*** exposed to reactor coolant in the Steam Generator. The pressurizer relief tank components are not exposed to treated borated water >60°C (>140°F).

e. Revise line 3.1.1-86 on page 3.3-42 as follows;

3.1.1-86	Stainless steel piping, piping components, and piping elements exposed to air-indoor uncontrolled (External); air with borated water leakage; concrete; gas	None	None	NA - No AEM or AMP	Components in Chemical and Volume Control, Residual Heat Removal, and Safety Injection systems have been aligned to this line item based on material, environment, and aging effect. Consistent with NUREG-1801. Stainless steel piping components exposed to air-indoor uncontrolled (external) and air with borated water leakage (external) are contained in the Chemical and Volume Control System, Reactor Coolant, Residual Heat Removal, and Safety Injection systems. Stainless steel heat exchanger components are contained in the Reactor Coolant system. Stainless steel pressurizer components, pressurizer diaphragm plate, pressurizer heater sleeves, pressurizer manway cover, and pressurizer safe end welds exposed to air-indoor uncontrolled (external) and air with borated water leakage are contained in the Reactor Coolant system. Stainless steel components, exposed to air-indoor uncontrolled (external) and air with borated water leakage are contained in the Reactor Vessel. Stainless steel piping components with gas environment are contained in the Reactor Coolant system. Stainless steel tanks exposed to air indoor uncontrolled (external) and air with borated water leakage (external) are contained in the Reactor Coolant System. Stainless steel steam generator channel head drain line coupling, ***primary nozzle weld,*** and primary nozzle safe ends exposed to air indoor uncontrolled (external) and air with borated water leakage (external) are contained in the Steam Generator.

f. On Table 3.1.2-4 on pages 3.1-104 and 105, revise the following line items for the Steam Generator Primary Nozzle Weld as follows:

Steam Generator Primary Nozzle Weld	Pressure Boundary	***Stainless Steel*** ~~Nickel Alloy~~	Air-Indoor Uncontrolled (External)	None	None	IV.E-~~1~~***2*** RP-***04***	3.1.1-~~85~~***86***	A
Steam Generator Primary Nozzle Weld	Pressure Boundary	***Stainless Steel*** ~~Nickel Alloy~~	Air With Borated Water Leakage (External)	None	None	***IV.E-3 (RP-05)*** ~~None~~	***3.1.1-86*** ~~None~~	~~G,2~~ ***A***
Steam Generator Primary Nozzle Weld	Pressure Boundary	***Stainless Steel*** ~~Nickel Alloy~~	Reactor Coolant (Internal)	Cracking	ASME Section XI Inservice Inspection Subsections IWB IWC and IWD Program Water Chemistry Program ~~Nickel Alloy Nozzles and Penetrations~~	IV.D1-***41*** (R-~~01~~***07***)	3.1.1-~~31~~***68***	A A
Steam Generator Primary Nozzle Weld	Pressure Boundary	***Stainless Steel*** ~~Nickel Alloy~~	Reactor Coolant (Internal)	Loss of Material	Water Chemistry Program	IV.B2-32 (RP-24)	3.1.1-83	~~A~~ ***C***
Steam Generator Primary Nozzle Weld	Pressure Boundary	***Stainless Steel*** ~~Nickel Alloy~~	Reactor Coolant (Internal)	Cumulative Fatigue Damage	TLAA	IV.D1-8 (R-221)	3.1.1-10	A

g. Revised Plant Specific Note 2 from Table 3.1.2-4 on page 3.1-113 as follows:

2	***Not Used*** ~~NUREG-1801 does not include air with borated water leakage environment for nickel alloy components. Similar to V.F-13 for stainless steel, there are no aging effects for nickel alloy in air with borated water leakage. Additionally, the American Welding Society (AWS) "Welding Handbook," (Seventh Edition, Volume 4, 1982, Library of Congress) identifies that nickel chromium alloy materials that are alloyed with iron, molybdenum, tungsten, cobalt or copper in various combinations have improved corrosion resistance.~~

<u>CHANGES TO SECTION 3.3:</u>

The following changes were made to Section 3.3 of the Seabrook Station LRA for the Auxiliary Boiler, Control Building Air Handling, Diesel Generator, Fire Protection, Instrument Air System, Plant Floor Drain, and Service Water systems due to the significant changes made to the Buried Piping and Tanks Inspection Program (Supplement 1). The Buried Piping and Tanks Inspection Program was revised and resubmitted as a plant specific program based on recent industry operating experience. Additionally, a) In the Fire Protection system, new AMR line items were added for stainless steel bolting and fiberglass piping in soil (external) environment, which was inadvertently omitted during the original LRA preparation, b) In the Instrument Air system, a new AMR line item was added for carbon steel piping in soil (external) environment, which was inadvertently omitted during the original LRA preparation, and c) In the Service Water system, new AMR line items were added for copper alloy >15% Zn, stainless steel, and steel bolting in raw water (external) environment for components located in the Service water system vault and valve pit, which were inadvertently omitted during the original LRA preparation.

1. In the Fire protection system, add the following bullet in Section 3.3.2.1.15 on page 3.3-26 under "Materials" (after Elastomer):

   - ***Fiberglass***

2. In the Fire Protection system, add the following bullet to Section 3.3.2.15 on page 3.3-27 under "Aging Effects Requiring Management" (after Cracking):

   - ***Cracking, Blistering, and Changes in Material Properties***

3. In the Instrument Air system, add the following bullet to Section 3.3.2.1.20 on page 3.3-34 under "Environments" (after Lubricating Oil):

   - ***Soil***

4. In the Instrument Air system, add the following bullet to Section 3.3.2.1.20 on Page 3.3-35 under "Aging Management Programs" (after Boric Acid Corrosion Program):

   - ***Buried Piping and Tanks Inspection Program (B.2.1.22)***

5. Revise the SRP 3.3.2.2.8 discussion on page 3.3-74 as follows:

3.3.2.2.8 Loss of Material due to General, Pitting, Crevice, and Microbiologically-Influenced Corrosion (MIC)

Loss of material due to general, pitting, crevice corrosion, and microbiologically-influenced corrosion (MIC) could occur for steel (with or without coating or wrapping) piping, piping components, and piping elements buried in soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general, pitting, and crevice corrosion and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

Seabrook Station will implement the ***plant specific*** Buried Piping and Tanks Inspection Program, B.2.1-22, to manage loss of material due to general, pitting, crevice, and microbiologically influenced corrosion of the steel piping components (with or without coating or wrapping) buried in soil in the Auxiliary Boiler, Control Building Air Handling, Fire Protection, ***Instrument Air,*** Plant Floor Drain, and Service Water systems. The Buried Piping and Tanks Inspection Program manages buried steel piping and components for loss of material through the use of coatings and wrappings, and periodic inspections. The program relies on preventive measures such as coating and wrapping to mitigate corrosion and periodic inspection of external surfaces to identify coating degradation, if coated, or base metal corrosion, if uncoated. These inspections assure that existing environmental conditions are not causing material degradation that could result in a loss of component intended functions. The Buried Piping and Tanks Inspection Program is described in Appendix B.

6. Revise the second paragraph for SRP 3.3.2.2.10, Item 7 on page 3.3-81 for the Diesel Generator System as follows:

The ***plant specific*** Buried Piping and Tanks Inspection Program, B.2.1.22 will be used to manage loss of material due to pitting, crevice, and microbiologically influenced corrosion (an additional aging mechanism) of the stainless steel piping components exposed to soil in the Diesel Generator system. The Buried Piping and Tanks Inspection program is described in Appendix B.

7. Revise line 3.3.1-19 on page 3.3-91 as follows:

3.3.1-19	Steel (with or without coating or wrapping) piping, piping components, and piping elements exposed to soil	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Buried Piping and Tanks Surveillance Or Buried Piping and Tanks Inspection	No Yes, detection of aging effects and operating experience are to be further evaluated	Consistent with NUREG-1801 ***for material, environment and aging effect, but a different aging management program is credited*** ~~with exceptions~~. The ***plant specific*** Buried Piping and Tanks Inspection Program ~~(with exceptions)~~, B.2.1.22, will be used to manage loss of material due to general, pitting, crevice, and microbiologically influenced corrosion of the steel piping components (with or without coating or wrapping) exposed to soil in the Auxiliary Boiler, Control Building Air Handling, Fire Protection, ***Instrument Air,*** Plant Floor Drain, and Service Water systems. See subsection 3.3.2.2.8.

8. Revise line 3.3.1-29 on page 3.3-96 as follows:

3.3.1-29	Stainless steel piping, piping components, and piping elements exposed to soil	Loss of material due to pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes, plant specific	Consistent with NUREG-1801 ~~with exceptions~~. The ***plant specific*** Buried Piping and Tanks Inspection Program ~~(with exceptions)~~, B.2.1.22, will be used to manage loss of material due to pitting, crevice, and microbiologically influenced corrosion (an additional aging mechanism) of the stainless steel piping components exposed to soil in the Diesel Generator system. See subsection 3.3.2.2.10.7.

9. Revise line 3.3.1-76 on page 3.3-113 as follows:

3.3.1-76	Steel piping, piping components, and piping elements (without lining/coating or with degraded lining/coating) exposed to raw water	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, fouling, and lining/coating degradation	Open-Cycle Cooling Water System	No	***Components in the Service Water System have been aligned to this line item based on material, environment, and aging effect but the plant specific Buried Piping and Tanks Inspection Program, B.2.1.22, will be substituted to manage loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping components (with or without coating or wrapping) exposed to raw water.*** Components in the Circulating Water system have been aligned to this line item based on material, environment, and aging effect. Consistent with NUREG-1801 with exceptions. The Open-Cycle Cooling Water System Program (with exceptions), B.2.1.11, will be used to manage loss of material due to general, pitting, crevice, and microbiologically influenced corrosion, fouling, and lining/coating degradation of the steel piping components exposed to raw water in the Service Water and Circulating Water systems. In addition, galvanic corrosion is an additional aging mechanism for the Service Water and Circulating Water systems.

10. Revise line 3.3.1-81 on page 3.3-117 as follows:

3.3.1-81	Copper alloy piping, piping components, and piping elements, exposed to raw water	Loss of material due to pitting, crevice, and microbiologically influenced corrosion, and fouling	Open-Cycle Cooling Water System	No	***Components in the Service Water System have been aligned to this line item based on material, environment, and aging effect but the plant specific Buried Piping and Tanks Inspection Program, B.2.1.22, will be substituted to manage loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion and fouling in copper alloy piping components exposed to raw water.*** Components in the Circulating Water system have been aligned to this line item due to material, environment, and aging effect. Consistent with NUREG 1801 with exceptions. The Open-Cycle Cooling Water System Program (with exceptions), B.2.1.11, will be used to manage loss of material due to pitting, crevice, and microbiologically influenced corrosion, and fouling of the copper alloy piping components exposed to raw water in the Service Water and Circulating Water systems. Components in the Chlorination, Dewatering, Plant Floor Drain, and Screen Wash systems have been aligned to this item number based on material, environment and aging effect. Consistent with NUREG 1801 with exceptions. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program (with exceptions), B.2.1.25, will be substituted to manage loss of material due to pitting, crevice, and microbiologically influenced corrosion, and fouling of the copper alloy piping components exposed to raw water in the Chlorination, Dewatering, Plant Floor Drain, and Screen Wash system. In addition, galvanic corrosion is an additional aging mechanism in the Dewatering and Screen Wash systems.

11. In the Auxiliary Boiler system, revise the fourth row in Table 3.3.2-1 on page 3.3-132 as follows:

Piping and Fittings	Pressure Boundary	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.H1-9 (A-01)	3.3.1-19	~~B~~ ***E, 1***

12. In the Auxiliary Boiler system, add the following new Plant Specific Note to Table 3.3.2-1 on page 3.3-135:

1	***NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

13. In the Control Building Air Handling system, revise the second row on Table 3.3.2-9 on page 3.3-244 as follows:

Piping And Fittings	Pressure Boundary	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.C1-18 (A-01)	3.3.1-19	~~B~~ ***E, 13***

14. In the Control Building Air Handling system, add the following new Plant Specific Note to Table 3.3.2-9 on page 3.3-252:

13	***NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

15. In the Diesel Generator system, revise note 11 on page 3.3-293 as follows:

11 NUREG-1801 specifies a plant-specific program for this line item. The ***plant specific*** Buried Piping and Tank***s*** Inspection Program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

16. In the Fire Protection system, add the following new rows after the fifth row in Table 3.3.2-15 on page 3.3-300:

Bolting	***Pressure Boundary***	***Stainless Steel***	***Soil (External)***	***Loss of Material***	***Buried Piping and Tanks Inspection Program***	***None***	***None***	***G***
Bolting	***Pressure Boundary***	***Stainless Steel***	***Soil (External)***	***Loss of Preload***	***Bolting Integrity Program***	***None***	***None***	***G***

17. In the Fire Protection system, add the following new rows after the sixth row in Table 3.3.2-15 on page 3.3-306:

Piping and Fittings	***Pressure Boundary***	***Fiberglass***	***Raw Water (Internal)***	***None***	***None***	***None***	***None***	***F, 6***
Piping and Fittings	***Pressure Boundary***	***Fiberglass***	***Soil***	***Cracking, Blistering, and Change in Material Properties***	***Buried Piping and Tanks Inspection Program***	***None***	***None***	***G***

18. In the Fire Protection system, revise the fourth row in Table 3.3.2-15 on page 3.3-308 as follows:

Piping and Fittings	Pressure Boundary	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.G-25 (A-01)	3.3.1-19	~~B~~ ***E, 7***

19. In the Fire Protection system, revise the eighth row in Table 3.3.2-15 on page 3.3-313 as follows:

Valve Body	Pressure Boundary	Gray Cast Iron	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.G-25 (A-01)	3.3.1-19	~~B~~ ***E, 7***

20. In the Fire Protection system, revise the last row in Table 3.3.2-15 on page 3.3-314 as follows:

Valve Body	Pressure Boundary	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.G-25 (A-01)	3.3.1-19	~~B~~ ***E, 7***

21. In the Fire Protection system, add the following new Plant Specific Notes to Table 3.3.2-15 on page 3.3-317:

6 ***Fiberglass components in condensation environment (external) and Raw Water environment (internal) are not exposed to high levels of ultraviolet radiation, high temperatures, or ozone, and therefore have no aging effects that require aging management. This is consistent with plant operating experience.***

7 ***NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

22. In the Instrument Air system, add the following row after the sixth row in Table 3.3.2-20 on page 3.3-357:

Piping and Fittings	***Pressure Boundary***	***Steel***	***Soil (External)***	***Loss of Material***	***Buried Piping and Tanks Inspection Program***	***VII.G-25 (A-01)***	***3.3.1-19***	***E, 6***

23. In the Instrument Air system, add the following new Plant Specific Note to Table 3.3.2-20 on page 3.3-367:

6 ***NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

24. In the Plant Floor Drain system, revise the fourth row in Table 3.3.2-26 on page 3.3-391 as follows:

Piping and Fittings	Leakage Boundary (Spatial)	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.H1-9 (A-01)	3.3.1-19	~~B~~ ***E, 4***

25. In the Plant Floor Drain system, add the following new Plant Specific Note to Table 3.3.2-26 on page 3.3-395:

4 ***NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

26. In the Service Water system, add the following rows after the third row in Table 3.3.2-37 on page 3.3-463:

Bolting	Pressure Boundary	Copper Alloy >15% Zn	Raw Water (External)	Loss of Preload	Bolting Integrity Program	None	None	G
Bolting	Pressure Boundary	Copper Alloy >15% Zn	Raw Water (External)	Loss of Material	Buried Piping and Tanks Inspection Program	None	None	G

27. In the Service Water system, add the following row after the seventh row in Table 3.3.2-27 on page 3.3-463:

Bolting	Pressure Boundary	Stainless Steel	Raw Water (External)	Loss of Material	Buried Piping and Tanks Inspection Program	None	None	G

28. In the Service Water system, add the following rows after the last row in Table 3.3.2-27 on page 3.3-463:

Bolting	Pressure Boundary	Steel	Raw Water (External)	Loss of Preload	Bolting Integrity Program	None	None	G
Bolting	Pressure Boundary	Steel	Raw Water (External)	Loss of Material	Buried Piping and Tanks Inspection Program	None	None	G

29. In the Service Water system, add the following row after the sixth row in Table 3.3.2-37 on page 3.3-469 to account for the service water piping contained in the service water vault and valve pit:

Piping and Fittings	Pressure Boundary	Steel	Raw Water (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.C1-19 (A-38)	3.3.1-76	E,9

30. In the Service Water system, revise the last row in Table 3.3.2-37 on page 3.3-469 as follows:

Piping and Fittings	Leakage Boundary (Spatial) Pressure Boundary	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VII.C1-18 (A-01)	3.3.1-19	~~B~~ E, 10

31. In the Service Water system, revise the first row in Table 3.3.2-37 on page 3.3-473 as follows:

Valve Body	Pressure Boundary	Copper Alloy >15% Zn	Raw Water (External)	Loss of Material	~~Open Cycle Cooling Water System Program~~ ***Buried Piping and Tanks Inspection Program***	VII.C1-9 (A-44)	3.3.1-81	~~B~~ ***E, 9***

32. In the Service Water system, add the following new Plant Specific Notes to Table 3.3.2-37 on page 3.3-477:

9 NUREG-1801 specifies the Open Cycle Cooling Water System Program. Since the component is inside a vault or pit that is submerged in ground water (an external environment of raw water) the plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

10 NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

CHANGES TO SECTION 3.4:

The following changes were made to Section 3.4 of the LRA for the Auxiliary Steam Condensate, Auxiliary Steam Heating, Condensate, and Feedwater systems due to changes made to the Buried Piping and Tanks Inspection Program (Supplement 1). The Buried Piping and Tanks Inspection Program was revised and resubmitted as a plant specific program based on recent industry operating experience. Additionally, in the Feedwater system, a new AMR line item was also added for carbon steel piping in soil (external) environment, which was inadvertently omitted during the original LRA preparation.

1. In the Auxiliary Steam Condensate system, add the following bullet in Section 3.4.2.1.2 on Page 3.4-4 under "Aging Management Programs" (after the Boric Acid Corrosion Program):

- ***Buried Piping and Tanks Inspection Program (B.2.1.22)***

2. In the Auxiliary Steam Heating system, add the following bullet in Section 3.4.2.1.3 on Page 3.4-5 under "Aging Management Programs" (after the Boric Acid Corrosion Program):

- ***Buried Piping and Tanks Inspection Program (B.2.1.22)***

3. In the Feedwater system, add the following bullet in Section 3.4.2.1.6 on Page 3.4-8 under "Environments" (after the Lubricating Oil):

- ***Soil***

4. In the Feedwater system, add the following bullet in Section 3.4.2.1.6 on Page 3.4-9 under "Aging Management Programs" (after the Boric Acid Corrosion Program):

   - ***Buried Piping and Tanks Inspection Program (B.2.1.22)***

5. Revise Section 3.4.2.2.5 discussion on page 3.4-15 as follows:

   3.4.2.2.5 Loss of Material due to General, Pitting, Crevice Corrosion, and Microbiologically-Influenced Corrosion

   1 Loss of material due to general, pitting and crevice corrosion, and MIC could occur in steel (with or without coating or wrapping) piping, piping components, piping elements and tanks exposed to soil. The buried piping and tanks inspection program relies on industry practice, frequency of pipe excavation, and operating experience to manage the effects of loss of material from general corrosion, pitting and crevice corrosion, and MIC. The effectiveness of the buried piping and tanks inspection program should be verified to evaluate an applicant's inspection frequency and operating experience with buried components, ensuring that loss of material is not occurring.

   Seabrook Station will implement the ***plant specific*** Buried Piping and Tanks Inspection Program, B.2.1.22, to manage loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion (MIC) in steel piping components exposed to soil in the Condensate ***and Feedwater*** system***s***. The Buried Piping and Tanks Inspection Program is described in Appendix B.

6. Revise the second paragraph for Section 3.4.2.2.7 on page 3.4-18 as follows:

   Seabrook Station will implement the ***plant specific*** Buried Piping and Tanks Inspection Program, B.2.1.22, to manage loss of material due to pitting, crevice, and in addition microbiologically-influenced corrosion (MIC) in stainless steel piping components exposed to soil in the Condensate system. The Buried Piping and Tanks Inspection Program is described in Appendix B.

7. Revise line 3.4.1-11 on Page 3.4-25 as follows:

3.4.1-11	Buried steel piping, piping components, piping elements, and tanks (with or without coating or wrapping) exposed to soil	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Buried Piping and Tanks Surveillance or Buried Piping and Tanks Inspection	No Yes, detection of aging effects and operating experience are to be further evaluated	Consistent with NUREG-1801 ***for material, environment and aging effect, but a different aging management program is credited.*** ~~with exceptions.~~ The ***plant specific*** Buried Piping and Tanks Inspection Program ~~(with exceptions)~~, B.2.1.22, will be used to manage loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion in steel piping components exposed to soil in the Condensate ***and Feedwater*** systems. See Subsection 3.4.2.2.5.1.

8. Revise line 3.4.1-17 on Page 3.4-27 as follows:

3.4.1-17	Stainless steel piping, piping components, and piping elements exposed to soil	Loss of material due to pitting and crevice corrosion	Plant specific	Yes, plant specific	Consistent with NUREG-1801 ~~for material, environment and aging effect, but a different aging management program is credited~~. The ***plant specific*** Buried Piping and Tanks Inspection Program ~~(with exceptions)~~, B.2.1.22, will be used to manage loss of material due to pitting, crevice, and in addition, microbiologically-influenced corrosion in stainless steel piping components exposed to soil in the Condensate system. See Subsection 3.4.2.2.7.2.

9. Revise line 3.4.1-22 on Page 3.4-29 as follows:

3.4.1-22	Steel bolting and closure bolting exposed to air with steam or water leakage, air-outdoor (external), or air-indoor uncontrolled (external);	Loss of material due to general, pitting and crevice corrosion; loss of preload due to thermal effects, gasket creep, and self-loosening	Bolting Integrity	No	***Consistent with NUREG-1801 for material, environment and aging effect, but a different aging management program is credited. The plant specific Buried Piping and Tanks Inspection Program, B.2.1.22, will be used to manage loss of material of the steel bolting exposed to air indoor uncontrolled (external) in the Auxiliary Steam Condensate and Auxiliary Steam Heating systems.*** Consistent with NUREG-1801. The Bolting Integrity Program, B.2.1.9, will be used to manage loss of material due to general, pitting, and crevice corrosion, and loss of preload due to thermal effects, gasket creep, and self-loosening in steel bolting exposed to air-indoor uncontrolled in the Auxiliary Steam, Auxiliary Steam Condensate, Auxiliary Steam Heating, Condensate, Feedwater, Main Steam, and Steam Generator Blowdown systems.

10. Revise line 3.4.1-28 on Page 3.4-30 as follows:

3.4.1-28	Steel external surfaces exposed to air-indoor uncontrolled (external), condensation (external), or air-outdoor (external)	Loss of material due to general corrosion	External Surfaces Monitoring	No	***Consistent with NUREG-1801 for material, environment and aging effect, but a different aging management program is credited. The plant specific Buried Piping and Tanks Inspection Program, B.2.1.22, will be used to manage loss of material of the steel external surfaces exposed to air indoor uncontrolled (external) in the Auxiliary Steam Condensate and Auxiliary Steam Heating systems.*** Consistent with NUREG-1801 with exceptions. The External Surfaces Monitoring Program (with exceptions), B.2.1.24, will be used to manage loss of material due to general corrosion on the steel external surfaces exposed to air-indoor uncontrolled (external) in the Auxiliary Steam, Auxiliary Steam Condensate, Auxiliary Steam Heating, Condensate, Feedwater, Main Steam, and Steam Generator Blowdown systems, and general, pitting, crevice, and galvanic corrosion of steel external surfaces in air-outdoor (external) in the Auxiliary Steam Condensate, and Main Steam systems, and general, pitting, and crevice corrosion of steel external surfaces in condensation (external) in the Circulating Water System.

11. In the Auxiliary Steam Condensate system, add the following row after the first row in Table 3.4.2-2 on Page 3.4-45:

Bolting	***Pressure Boundary***	***Steel***	***Air-Indoor Uncontrolled (External)***	***Loss of Material***	***Buried Piping and Tanks Inspection Program***	***VIII.H-4 (S-34)***	***3.4.1-22***	***E, 3***

12. In the Auxiliary Steam Condensate system, add the following row after the third row in Table 3.4.2-2 on Page 3.4-48:

Piping and Fittings	***Pressure Boundary***	***Steel***	***Air-Indoor Uncontrolled (External)***	***Loss of Material***	***Buried Piping and Tanks Inspection Program***	***VIII.H-7 (S-29)***	***3.4.1-28***	***E, 4***

13. In the Auxiliary Steam Condensate system, add the following row after the fourth row in Table 3.4.2-2 on Page 3.4-51:

Trap	***Pressure Boundary***	***Gray Cast Iron***	***Air-Indoor Uncontrolled (External)***	***Loss of Material***	***Buried Piping and Tanks Inspection Program***	***VIII.H-7 (S-29)***	***3.4.1-28***	***E, 4***

14. In the Auxiliary Steam Condensate system, add the following row after the first row in Table 3.4.2-2 on Page 3.4-54:

Valve Body	*Pressure Boundary*	*Steel*	*Air-Indoor Uncontrolled (External)*	*Loss of Material*	*Buried Piping and Tanks Inspection Program*	*VIII.H-7 (S-29)*	*3.4.1-28*	*E, 4*

15. In the Auxiliary Steam Condensate system, add the following new Plant Specific Notes to Table 3.4.2-2 on Page 3.4-56:

3 ***NUREG-1801 specifies the Bolting Integrity Program for this line item. Since the component is in an underground pit that has an external environment of air indoor uncontrolled, the plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

4 ***NUREG-1801 specifies the External Surfaces Monitoring Program for this line item. Since the component is in an underground pit that has an external environment of air indoor uncontrolled, the plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.***

16. In the Auxiliary Steam Heating system, add the following row after the first row in Table 3.4.2-3 on Page 3.4-57:

Bolting	*Pressure Boundary*	*Steel*	*Air-Indoor Uncontrolled (External)*	*Loss of Material*	*Buried Piping and Tanks Inspection Program*	*VIII.H-4 (S-34)*	*3.4.1-22*	*E, 4*

17. In the Auxiliary Steam Heating system, add the following row after the third row in Table 3.4.2-3 on Page 3.4-58:

Filter Housing	*Pressure Boundary*	*Steel*	*Air-Indoor Uncontrolled (External)*	*Loss of Material*	*Buried Piping and Tanks Inspection Program*	*VIII.H-7 (S-29)*	*3.4.1-28*	*E, 5*

18. In the Auxiliary Steam Heating system, add the following row after the fifth row in Table 3.4.2-3 on Page 3.4-61:

Piping and Fittings	*Pressure Boundary*	*Steel*	*Air-Indoor Uncontrolled (External)*	*Loss of Material*	*Buried Piping and Tanks Inspection Program*	*VIII.H-7 (S-29)*	*3.4.1-28*	*E, 5*

19. In the Auxiliary Steam Heating system, add the following row after the first row in Table 3.4.2-3 on Page 3.4-64:

Valve Body	***Pressure Boundary***	***Steel***	***Air-Indoor Uncontrolled (External)***	***Loss of Material***	***Buried Piping and Tanks Inspection Program***	***VIII.H-7 (S-29)***	***3.4.1-28***	***E, 5***

20. In the Auxiliary Steam Heating system, add the following new Plant Specific Notes to Table 3.4.2-3 on Page 3.4-66:

4 NUREG-1801 specifies the Bolting Integrity Program for this line item. Since the component is in an underground pit that has an external environment of air indoor uncontrolled, the plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

5 NUREG-1801 specifies the External Surfaces Monitoring Program for this line item. Since the component is in an underground pit that has an external environment of air indoor uncontrolled, the plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

21. In the Condensate system, revise the third row in Table 3.4.2-5 on page 3.4-73 as follows:

Piping and Fittings	Pressure Boundary	Steel	Soil (External)	Loss of Material	Buried Piping and Tanks Inspection Program	VIII.E-1 (S-01)	3.4.1-11	~~B~~ ***E, 2***

22. In the Condensate system, revise Plant Specific Note 1 in Table 3.4.2-5 on page 3.4-76 as follows:

1 NUREG-1801 specifies a plant-specific program for this line item. The ***plant specific*** Buried Piping and Tank***s*** Inspection Program is used to manage the aging effect(s) applicable to this component type, material, and environment combination.

23. In the Condensate system, add the following Plant Specific Note to Table 3.4.2.5 on page 3.4-76:

2 NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

24. In the Feedwater system, add the following row after the third row in Table 3.4.2-6 on Page 3.4-84:

Piping and Fittings	*Pressure Boundary*	*Steel*	*Soil (External)*	*Loss of Material*	*Buried Piping and Tanks Inspection Program*	*VIII.G-1 (S-01)*	*3.4.1-11*	*E, 1*

25. In the Feedwater system, add the following new Plant Specific Note to Table 3.4.2-6 on Page 3.4-90:

1 NUREG-1801 specifies the Buried Piping and Tanks Inspection Program for this line item. The plant specific Buried Piping and Tanks Inspection Program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

CHANGES TO SECTION 3.5:

1. Evaluation of carbon steel exposed to air-indoor uncontrolled and air-outdoor is added for the Intake and Discharge Transition Structures. The revision to LRA Section 3.5, Table 3.5.2-1 (page 3.5-50) is shown below:

BSAS Carbon Steel DISCHARGE TRANSITION STRUCTURE Exposed to Air Indoor Uncontrolled	*Structural Support*	*Steel*	*Air Indoor Uncontrolled (External)*	*Loss of Material*	*Structures Monitoring Program*	*III.A3-12 (T-11)*	*3.5.1-25*	*A*
BSAS Carbon Steel DISCHARGE TRANSITION STRUCTURE Exposed to Air Outdoor	*Structural Support*	*Steel*	*Air Outdoor (External)*	*Loss of Material*	*Structures Monitoring Program*	*III.A3-12 (T-11)*	*3.5.1-25*	*A, 503*
BSAS Carbon Steel INTAKE TRANSITION STRUCTURE Exposed to Air Indoor Uncontrolled	*Structural Support*	*Steel*	*Air Indoor Uncontrolled (External)*	*Loss of Material*	*Structures Monitoring Program*	*III.A3-12 (T-11)*	*3.5.1-25*	*A*
BSAS Carbon Steel INTAKE TRANSITION STRUCTURE Exposed to Air Outdoor	*Structural Support*	*Steel*	*Air Outdoor (External)*	*Loss of Material*	*Structures Monitoring Program*	*III.A3-12 (T-11)*	*3.5.1-25*	*A, 503*

2. items for thermal insulation are being added to the Seabrook Station License Renewal Application. Add line item and note 517 to Section 3.5, Table 3.5.2-6 (page 3.5-239 and 240) as shown below:

Thermal Insulation – Exposed to Air Indoor Uncontrolled	*Insulate*	*Non-Metallic Insulation*	*Air Indoor Uncontrolled (External)*	*None*	*None*	*None*	*None*	*J, 517*

517 ***At Seabrook Station, thermal insulation was treated as a passive, long lived component. There is no aging effect for thermal insulation in an "air-indoor uncontrolled" environment.***

3. In Section 3.5.2.1.6 (page 3.5-8), add the following bullet to "Materials" list:

- ***Thermal Insulation***

Enclosure 3 to SBK-L-10192

Changes to the

Seabrook Station License Renewal Application

Associated with

Chapter 4 – Time Limited Aging Analyses

Introduction

This Enclosure contains an update to the information provided in the NextEra Energy Seabrook License Renewal Application (LRA) Chapter 4 – Time Limited Aging Analyses. Included in this update are changes to LRA Section 4.3 and Table 4.1-1. For clarity, entire sentences or paragraphs from the LRA are provided with deleted text highlighted by strikethroughs and inserted text highlighted by bolded italics.

Description of Changes

Changes made to the Seabrook License Renewal Application (LRA) Time Limited Aging Analyses include the following editorial changes:

1. The disposition in Table 4.1-1 "Reactor Vessel Internal Aging Management" has been changed from §54.21(c)(1)(i) to §54.21(c)(1)(iii) to reflect the current disposition in Section 4.3.3 of 54.21(c)(1)(iii). On page 4.1-5 revise Table 4.1-1 as follows:

Table 4.1-1 Time-Limited Aging Analyses Applicable to Seabrook Station			
TLAA Category	Description	Disposition Method(s)	LRA Section
2.	Metal Fatigue Of Piping And Components		4.3
	Nuclear Steam Supply System (NSSS) Pressure Vessel and Component Fatigue Analyses	§54.21(c)(1)(i)	4.3.1
	Supplementary ASME Section III, Class 1 Piping and Component Fatigue Analyses	§54.21(c)(1)(i)	4.3.2
	Absence of a TLAA for Thermal Stresses in Piping Connected to Reactor Coolant Systems: NRC Bulletin 88-08	N/A	4.3.2.1
	NRC Bulletin 88-11, Pressurizer Surge Line Thermal Stratification	§54.21(c)(1)(i)	4.3.2.2
	Reactor Vessel Internal Aging Management	~~§54.21(c)(1)(i)~~ ***§54.21(c)(1)(iii)***	4.3.3
	Environmentally-Assisted Fatigue Analyses	§54.21(c)(1)(ii) §54.21(c)(1)(iii)	4.3.4
	Steam Generator Tube, Loss of Material and Fatigue from Flow-Induced Vibration	§54.21(c)(1)(i)	4.3.5
	Absence of TLAAs for Fatigue Crack Growth, Fracture Mechanics Stability, or Corrosion Analyses Supporting Repair of Alloy 600 Materials	N/A	4.3.6
	Non-Class 1 Component Fatigue Analyses	§54.21(c)(1)(i)	4.3.7

2. The disposition in Section 4.3.4 in the paragraph is changed from 54.21(c)(1)(i) to 54.21(c)(1)(ii) to provide consistency to the disposition header. Revise Section 4.3.4, page 4.3-23, first paragraph (Disposition) as follows:

   Revision 10 CFR 54.21(c)(1)(ii) - The evaluation of environmental fatigue effects for the Reactor Vessel Shell and Lower Head and Reactor Vessel Inlet and Outlet Nozzles determined that the CUF will remain below the ASME code allowable fatigue limit of 1.0 using the maximum applicable F_{en}, applied to CUF based on the design number of transients for these locations, when extended to 60 years. The evaluation of fatigue effects for these locations has thereby been validated for the period of extended operation, in accordance with ~~10 CFR 54.21(c)(1)(i)~~ ***10 CFR 54.21(c)(1)(ii)***, including effects of the reactor coolant environment. Therefore, no aging management program is necessary to address environmentally-assisted fatigue for these components.

3. "Primary loop piping and pressurizer surge line piping" is removed from Section 4.3.7, as Section 4.3.2 focuses on Class 1 Piping and Section 4.3.7 focuses on non-Class 1 Piping. Revise Section 4.3.7 (Summary Description), page 4.3-27, first paragraph as follows:

   The following non-Class 1 Seabrook Station systems that are in scope for license renewal were designed in accordance with ASME Section III Class 2 and 3 requirements:

   - Reactor Coolant System ~~(including primary loop piping and pressurizer surge line piping)~~
   - Chemical and Volume Control System
   - Safety Injection System
   - Primary Component Cooling Water
   - Service Water
   - Sample System
   - Residual Heat Removal System
   - Main Steam System
   - Condensate and Feedwater Systems
   - Steam Generator Blowdown System

Enclosure 4 to SBK-L- 10192

Changes to the

Seabrook Station License Renewal Application

Associated with

Appendix A – Updated UFSAR Supplement

and

Appendix B – Aging Management Programs

<u>Description of Changes</u>

The following editorial changes have been made to Appendix A and Appendix B of the Seabrook License Renewal Application (LRA):

1. LRA Appendix A and Appendix B are revised to change an inadvertent reference to "in-core". The correction changes "in-core" to "in-scope".

   a. Revise LRA Appendix A, second paragraph of Section A.2.1.33 (page A-17) as follows:

      The program shall perform insulation resistance tests on the ~~in-core~~ ***in-scope*** neutron flux monitoring cable and connections in the Nuclear Instrumentation System.

   b. Revise LRA Appendix B, Section B.2.1.33 (page B-178) "Program Description", paragraph 1 and 3, and "Operating Experience", item #2 (page B-180) as shown below:

      Program Description

      The Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits Program is a new program that will manage the aging effects of reduced insulation resistance due to exposure to adverse localized environments caused by heat, radiation, or moisture in the presence of oxygen, causing increased leakage currents. This program applies to sensitive instrumentation cable and connection circuits with low-level signals in the in-scope portions of ~~in-core~~ ***the*** neutron flux monitoring cable in the Nuclear Instrumentation System. These cables are not included in the Seabrook Station EQ Program.

      This program considers the technical information and guidance provided in the following:

      a. NUREG/CR-5643, *"Insights Gained From Aging Research"*

      b. IEEE Std. P1205, *"IEEE Guide for Assessing, Monitoring and Mitigating Aging Effects on Class 1E Equipment Used in Nuclear Power Generating Stations"*

      c. SAND96-0344, *"Aging Management Guidelines for Commercial Nuclear Power Plants – Electrical Cable and Terminations"*

d. EPRI TR-109619, *"Guideline for the Management of Adverse Localized Equipment Environments"*

These in-scope ~~in-core~~ neutron flux monitoring cables and connections in the Nuclear Instrumentation System are routed inside containment and potentially exposed to moisture, radiation, and high temperatures. The high voltage low-level signal instrumentation circuits from the Radiation Monitoring System are not included in this program. These cables are included in the Seabrook Station EQ program.

Operating Experience

2. Plant specific operating experience was reviewed. Insulation resistance tests have been performed on the in-scope sensitive instrumentation cable and connections.

   In 2008, testing was performed on all ~~in-core~~ ***in-scope*** neutron flux monitoring cables and connections. The test results documented a less than expected insulation resistance reading between the inner and outer shield. The low insulation resistance reading was attributed to the connector design. The design issue was resolved and retesting found the cable and connection to be acceptable. Although this example is not representative of age related degradation, it does demonstrate that the test method is an acceptable for identifying degraded conditions.

2. The Metal Enclosed Bus aging management program descriptions in LRA Appendix B, Section B.2.1.35 are revised to clarify that if thermography is used to identify loose connections utilizing inspection techniques that it will provide accurate temperature readings. In addition this change adds connection resistance measurements as an alternative method to determine if metal enclosed bus connections are loose. Revise LRA Appendix B, Section B.2.1.35, page B-185 paragraphs 2 and 4 as follows:

The internal portions of the in-scope metal enclosed bus enclosures will be visually inspected for aging degradation of insulating material and for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of moisture intrusion. The bus insulation will be visually inspected for signs of embrittlement, cracking, melting, swelling, or discoloration, which may indicate overheating or aging degradation. The isolated phase bus conductor is not insulated. The internal bus supports will be visually inspected for structural integrity and signs of cracks. The accessible bus sections will be inspected for loose connections using thermography ~~from outside the metal enclosed bus while the bus is energized~~ ***inspection techniques that will provide accurate temperature readings of the bus bolted connection***

temperatures, such as through view ports. As an alternative to thermography, connection resistance measurements may be used to determine if the in-scope MEB's have loose connections due to thermal cycling and ohmic heating.

The program requires that bolted connections be below the maximum allowed temperature for the application, and free of unacceptable visual defects.

Unacceptable thermography heat signatures, ***connection resistance measurements*** or ~~unacceptable~~ visual indications are entered into the Corrective Action Program.

3. The Fuse Holder aging management program description in LRA Appendix B, Section B.2.1.36 is revised to clarify the exclusion of certain aging mechanisms from the aging management program. Revise LRA Appendix B, Section B.2.1.36 "Program Description" on page B-188, fourth full paragraph as follows:

   The ***following*** Seabrook Station analysis shows that the aging effects due to thermal fatigue in the form of high resistance caused by ohmic heating~~,~~ ***and*** thermal cycling***,*** ~~or~~ electrical transients, mechanical fatigue caused by frequent ***manipulation (***removal/replacement of the fuse***),*** ~~or~~ vibration ***and chemical contamination*** do not require aging management.

   Ohmic Heating and Thermal Cycling

   Seabrook Station power circuits are sized so that the ohmic heating is approximately 60 percent of the cable's rated temperature. Therefore ohmic heating of the fuse clamps is minimized. Without ohmic heating, the mechanism of thermal cycling on the metallic portion of the fuse clips is minimized. Ohmic heating and thermal cycling are not considered possible aging mechanisms for the fuse holders within the scope of this evaluation.

   Electrical Transients

   Seabrook Station electrical design ensures that stresses due to forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. Mechanical stress due to electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. Electrical transients are not considered an aging mechanism that requires management.

Frequent Manipulation

A review of the Seabrook Station operations database was performed to determine if fuses are frequently pulled. Of all in-scope fuses which are held in place by metallic (non-bolted) fuse clips only 7 have been pulled during the life of the plant. Frequent manipulation of in-scope fuses is not considered an aging mechanism that requires management.

Vibration

The exact location and mounting of the fuse holders within the scope of this evaluation was determined by a review of the Seabrook Station drawings and documentation. This documentation verifies that there are no direct sources of vibration in proximity to the fuse holder junction boxes. The fuse holder junction boxes are mounted to a support attached directly to either a concrete wall or a column. Therefore, vibration is not considered an applicable aging mechanism.

Chemical Contamination

The exact location and mounting of the fuse holders within the scope of this evaluation was determined by a review of the Seabrook Station drawings and documentation. The areas have no potential sources of chemical contamination in the area, and the fuse holders are housed in a protective enclosure to preclude this aging mechanism even if chemical contamination were possible. Therefore, based on their installed location and design configuration, chemical contamination is not considered an applicable aging mechanism.

4. Revise LRA Appendix A (A.2.1.31) and Appendix B (B.2.1.31) to reference the use of ACI-349.

   a) Revision to LRA Appendix A, Section A.2.1.31, page A-17 first paragraph, is shown below:

   The Structures Monitoring Program is implemented through the plant Maintenance Rule Program, which is based on the guidance provided in NRC Regulatory Guide 1.160 "*Monitoring the Effectiveness of Maintenance at Nuclear power Plants*" and NUMARC 93-01 "*Industry Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants*"***, and with guidance from ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures"***. The Structures

Monitoring Program was developed using the guidance of these ~~two~~ ***three*** documents. The Program is implemented to monitor the condition of structures and structural components within the scope of the Maintenance Rule, such that there is no loss of structure or structural component intended function.

b) Revision to LRA Appendix B, Section B.2.1.31, "Program Description", page B-164, is shown below:

The Seabrook Station Structures Monitoring Program is an existing program that will be enhanced to ensure provision of aging management for structures and structural components including bolting within the scope of this program. The Structures Monitoring Program is implemented through the Seabrook Station Maintenance Rule Program, which is based on the guidance provided in NRC Regulatory Guide 1.160, Revision 2, *"Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"* and NUMARC 93-01, Revision 2, *"Industry Guidance for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants"****, and with guidance from ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures".*** The Seabrook Station Structures Monitoring Program was developed using the guidance of these ~~two~~ ***three*** documents to monitor the condition of structures and structural components within the scope of the Maintenance Rule, such that there is no loss of structure or structural component intended function.

5. Revise LRA Table A.3, License Renewal Commitment List and Appendix B, Aging Management Programs B.2.1.16, B.2.1.17, B.2.1.20 and B.2.1.21 to clarify commitment schedule.

   a) Revision to LRA Appendix A, Section A.3 (page A-37) is shown below:

10	Fire Water System	Enhance the program to include the performance of periodic flow testing of the fire water system in accordance with the guidance of NFPA 25.	A.2.1.16	~~Within ten years of entering the period of extended operation.~~ ***Prior to the period of extended operation.***
11	Fire Water System	Enhance the program to include the performance of periodic visual inspection of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance. ~~This~~ ***These*** inspections will be performed ~~no earlier than 10 years before~~ ***within ten years prior to*** the period of extended operation.	A.2.1.16	~~Prior~~ ***Within ten years prior*** to the period of extended operation.

b) Revision to LRA Appendix A, Section a.3 (Page A-37) is shown below:

13.	Aboveground Steel Tanks	Enhance the program to include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks.	A.2.1.17	~~Within ten years of entering the period of extended operation.~~ ***Within ten years prior to the period of extended operation.***

c) Revision to LRA Appendix A, Section a.3 (Page A-39) is shown below:

22.	One-Time Inspection	Implement the One Time Inspection Program.	A.2.1.20	~~Within ten years of entering the period of extended operation.~~ ***Within ten years prior to the period of extended operation.***
23.	Selective Leaching of Materials	Implement the Selective Leaching of Materials Program.	A.2.1.21	~~Within five years of entering the period of extended operation.~~ ***Within five years prior to the period of extended operation.***

25.	One-Time Inspection of ASME Code Class 1 Small Bore-Piping	Implement the One-Time Inspection of ASME Code Class 1 Small Bore-Piping Program.	A.2.1.23	~~Within ten years of entering the period of extended operation.~~ ***Within ten years prior to the period of extended operation.***

d) Revision to LRA Appendix B, Section B.2.1.16 (page B-101) is shown below:

2. The Seabrook Station Fire Water System Program will be enhanced to include the performance of periodic flow testing of the fire water system in accordance with NFPA 25 guidelines***, prior to the period of extended operations.***

   Program Elements Affected: Element 3 (Parameters Monitored/Inspected)

3 The Seabrook Station Fire Water System Program will be enhanced to include the performance of periodic visual inspection or volumetric inspection, as required, of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance to evaluate wall thickness and inner diameter of the fire protection piping. ~~This~~***These*** inspections will be performed ~~no earlier than 10 years before~~ ***within ten years prior to*** the period of extended operation.

   Program Elements Affected: Element 4 (Detection of Aging Effects)

e) Revision to LRA Appendix B, Section B.2.1.17 (page B-104) is shown below:

Enhancements

2. Enhance the Seabrook Station Aboveground Steel Tanks Program implementing procedures to require the performance of an ultrasonic examination and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks within ~~10~~***ten*** years prior to the period of extended operation.

Program Elements Affected: Element 1 (Scope of Program), Element 3 (Parameters Monitored/Inspected), Element 4 (Detection of Aging Effects), Element 5 (Monitoring and Trending), and Element 6 (Acceptance Criteria)

f) Revision to LRA Appendix B, Section B.2.1.20 (page B-119) is shown below:

Program Description

The inspections will be scheduled ~~as close to the end of the current operating license period as practical, with margin provided to ensure completion prior to commencing~~ ***within ten years prior to*** the period of extended operation. The inspection requirements may be satisfied by a review of repair or other inspection records to confirm that the component has been inspected for aging degradation and no significant degradation has occurred within ten years prior to the period of extended operation.

g) Revision to LRA Appendix B, Section B.2.1.17 (page B-121, 122) is shown below:

Program Description

The Seabrook Station Selective Leaching of Materials Program will include a one-time inspection of selected components that may be susceptible to selective leaching. Because selective leaching is a slow acting corrosion process, the one-time inspection for selective leaching will be performed within ~~the last~~ five years prior to ~~entering~~ the period of extended operation.

Enclosure 5 to SBK-L-10192

Changes to the

Seabrook Station License Renewal Application

Associated with the Protective Coating Monitoring and

Maintenance Program B.2.1.38

Introduction

As a result of interactions during the recent NRC Aging Management Program Audit activities at Seabrook Station and review of significant industry operating experience, NextEra Energy Seabrook, LLC has added a Protective Coating Monitoring and Maintenance Program to the Seabrook Station License Renewal Application (LRA).

Description of Changes

1. CHANGES to CHAPTER 4

a) Revise Section 4.7.7, "Service Level 1 Coatings Qualification", disposition on page 4.7-9 as follows:

Disposition

Aging Management - 10 CFR 54.21(c)(1)(iii) - Seabrook Station Service Level I Coatings are managed by the ~~ASME Section XI, Inservice Inspection, Subsection IWE Program, B.2.1.27~~ ***Protective Coating Monitoring and Maintenance Program B.2.1.38*** and Procedure for Application of Service Level I Coatings. Seabrook Station periodically conducts condition assessments of Service Level I coatings inside containment. Coating inspections are performed at the beginning and at the end of each refueling outage. Inspections at the beginning of the refueling outage are performed by a NextEra Energy Coating Supervisor and a Design Engineer for peeling coatings that have the potential of falling into the reactor or Containment Building Spray recirculation sumps.

2. CHANGES to APPENDIX A

a) Add line A.2.1.38 to APPENDIX A - Table of Contents, page A-2, as follows:

b) Add Item #38 to Section A.1.1, NUREG-1801 Chapter XI aging management programs, on page A-5, as follows:

37. Electrical Cable Connections Not Subject to 10 CFR 50.49 EQ Requirements (A.2.1.37)

38. Protective Coating Monitoring and Maintenance (A.2.1.38)

c) Add new section A.2.1.38 to page A-10, as follows:

A.2.1.38 Protective Coating Monitoring and Maintenance

The Protective Coating Monitoring and Maintenance program manages cracking, blistering, flaking, peeling, and delamination of the Service Level I coatings consistent with the guidelines of Regulatory Position C4 of the Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Rev. 1) as described in NUREG 1801, Rev. 1.

At the beginning of every refueling outage, the NextEra Energy Coating Supervisor and the Design Engineer shall inspect all areas and components from which peeling coatings have the potential of falling into the reactor cavity or CBS [Emergency Core Cooling System (ECCS)] recirculation sumps. These areas and components shall include but not be limited to the following as applicable: polar crane, refueling machine, manipulator crane, CRDM cooling fan shrouds, wall and equipment adjacent to reactor cavity, carbon steel supports and hangers within the reactor cavity.

The determination of acceptability of the coatings will be made by the Design Engineer. The inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Data derived from the inspections shall be reviewed by the Design Engineer so that the coatings condition assessment can be used to trend material condition and to provide strategic planning for required maintenance activities.

d) Revise Section A.2.4.5.6, "Service Level 1 Coatings Qualification", page A-34 as follows:

A.2.4.5.6 Service Level I Coatings Qualification

Service Level 1 coatings used at Seabrook Station are in compliance with the applicable ANSI standards for coating systems inside containment. In a design basis accident, the Emergency Core Cooling System (ECCS) at Seabrook Station pumps water from inside the containment sump to the reactor vessel to keep the core covered with water and make up losses from the pipe break location. These coatings could potentially detach during a design basis accident and the coating debris could contribute to flow blockage of ECCS suction strainers. The ECCS has suction piping located below the waterline inside the sump. Since it is assumed that the degree of radiation exposure used in the original qualification testing was intended to bound 40 years of operation, qualification of Service Level 1 coatings is considered a TLAA.

Seabrook Station Service Level I Coatings are managed by the ~~ASME Section XI, Inservice Inspection, Subsection IWE Program, B.2.1.27~~ ***Protective Coating Monitoring and Maintenance Program B.2.1.38*** and Procedure for Application of Service Level I Coatings. Seabrook Station periodically conducts condition assessments of Service Level I coatings inside containment.

e) Add line items 46, 47, 48 & 49 to Table A.3, "License Renewal Commitment List", page A-43 as follows:

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
46.	Protective Coating Monitoring and Maintenance	Enhance the program by designating and qualifying an Inspector Coordinator and an Inspection Results Evaluator.	A.2.1.38	Prior to the period of extended operation
47.	Protective Coating Monitoring and Maintenance	Enhance the program by including, "Instruments and Equipment needed for inspection may include, but not be limited to, flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, and self sealing polyethylene sample bags."	A.2.1.38	Prior to the period of extended operation
48.	Protective Coating Monitoring and Maintenance	Enhance the program to include a review of the previous two monitoring reports.	A.2.1.38	Prior to the period of extended operation
49.	Protective Coating Monitoring and Maintenance	Enhance the program to require that the inspection report is to be evaluated by the responsible evaluation personnel, who is to prepare a summary of findings and recommendations for future surveillance or repair.	A.2.1.38	Prior to the period of extended operation

3. CHANGES to APPENDIX B

a) Add B.2.1.38 to Appendix B - Table of Contents, page B-2 as follows:

b) Add line 41 to B.1.5, "NUREG-1801 CHAPTER XI AGING MANAGEMENT PROGRAMS" on page B-10 as follows:

41. Protective Coating Monitoring and Maintenance (B.2.1.38) [Existing]

c) Revised B.2.0, "Aging Management Correlation Chart- NUREG-1801 To Seabrook Station Programs", on page B-13 as follows:

NUREG-1801 Number	NUREG-1801 Program	Seabrook Station Program
XI.S8	Protective Coating Monitoring and Maintenance Program	~~Not Used. Not credited for aging management.~~ ***Protective Coating Monitoring and Maintenance Program***

d) Add to B.2.0, "NUREG-1801 Chapter XI Aging Management Programs", new Section B.2.1.38, Protective Coating Monitoring and Maintenance Program, to page B-192, as follows:

B.2.1.38 Protective Coating Monitoring and Maintenance

Program Description

The Seabrook Station Protective Coating Monitoring and Maintenance program is an existing program. During construction the interior containment carbon steel surfaces (e.g., steel liner, penetrations, hatches) were coated to meet the guidance of Regulatory Guide 1.54, Rev. 0. The Protective Coating Monitoring and Maintenance program manages cracking, blistering, flaking, peeling, and delamination of the Service Level I coatings consistent with the guidelines of Regulatory Position C4 of the Nuclear Regulatory Commission [NRC] Regulatory Guide [RG] 1.54, Rev. 1 as described in NUREG 1801, Rev. 1.

At the beginning of every refueling outage, the NextEra Energy Coating Supervisor and the Design Engineer shall inspect all areas and components from which peeling coatings have the potential of falling into the reactor cavity or CBS [Emergency Core Cooling System (ECCS)] recirculation sumps. These areas and components shall include but not be limited to the following as applicable: polar crane, refueling machine, manipulator crane, CRDM cooling fan shrouds, wall and equipment adjacent to reactor cavity, carbon steel supports and hangers within the reactor cavity.

After completion of all Containment Closeout work, the Coating Supervisor shall notify the Design Engineer and the Nuclear Coating Specialist to perform the Containment Closeout Inspection. Unqualified coatings found during this inspection shall be evaluated based on size, location and coating type. Based on the results of this evaluation the unqualified coating shall be removed as directed by the Design Engineer or documented on the Containment Coatings Closeout Inspection form and on an AR.

With respect to loss of material due to corrosion of carbon steel elements, this program is a preventive action. Proper preparation of carbon steel surfaces, application of coatings, and maintenance of coatings helps prevent loss of material of the carbon steel surfaces coated with Service Level I coatings.

The program inspects the Service Level I coatings for visible signs of degradation such as blistering, cracking, flaking, peeling, delamination, rust, or physical damage. Any degradation observed during the inspection will be documented and tracked by an Action Request (AR). The program monitors the conditions of the Service Level I coatings during refueling outages and uses the Action Request to resolve non-conforming coatings and those experiencing degradation.

The program requires that all accessible areas of containment receive a coatings inspection of all Service Level I coatings. These inspections are pre-planned and performed during each refueling outage. These inspections are performed by qualified coatings inspectors. These individuals (An Inspector Coordinator and an Inspection Results Evaluator) are qualified per the requirements of ANSI N45.2.6.

Instruments and Equipment needed for inspection may include, but not be limited to, flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, and self sealing polyethylene sample bags.

The Design Engineer reviews previous inspection notes attached to the Containment Coatings Closeout Inspection (A minimum of two previous inspections) prior to the next inspection. This review will ensure all previously identified degraded/ deteriorated coatings will be identified for inspection during the next refueling outage.

The inspection field notes document the approximate location and square footage of identified degraded/deteriorated coatings which have not been removed and do not require removal prior to start-up. Data derived from the inspections shall be reviewed by the Design Engineer so that the coatings condition assessment can be used to trend material condition and to provide strategic planning for required maintenance activities.

The determination of acceptability of the coatings will be made by the qualified inspection personnel. This determination, as well as any deteriorated or unqualified coatings identified, will be documented in the as-left Action Request (AR).

The determination of acceptability of the coatings will be made by the Design Engineer. The inspection report is to be evaluated by the responsible evaluation personnel, who prepare a summary of findings and recommendations for future surveillance or repair, including an analysis of reasons or suspected reasons for failure. Data derived from the inspections shall be reviewed by the Design Engineer so that the coatings condition assessment can be used to trend material condition and to provide strategic planning for required maintenance activities.

NUREG-1801 Consistency

This program is consistent with NUREG-1801 XI.S8.

Exceptions to NUREG-1801

There are no exceptions to NUREG 1801 XI.S8.

Enhancements

The following enhancement will be made prior to entering the period of extended operation.

1. Enhance the program by designating and qualifying an Inspector Coordinator and an Inspection Results Evaluator.

   Element affected; Detection of Aging Effects.

2. Enhance the program by including, "Instruments and Equipment needed for inspection may include, but not be limited to, flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, and self sealing polyethylene sample bags."

   Element affected; Detection of Aging Effects

3. Enhance the program to include a review of the previous two monitoring reports.

Element affected; Monitoring and Trending

4. Enhance the program to require that the inspection report is to be evaluated by the responsible evaluation personnel, who is to prepare a summary of findings and recommendations for future surveillance or repair.

   Element affected; Acceptance Criteria

Operating Experience

The existing Seabrook Station Protective Coating Monitoring and Maintenance program has been effective in identifying degraded/ deteriorated Service Level I coatings. The following operating experience demonstrates program effectiveness:

1. In June 2010 an Action Request (AR) was issued to review NRC Information Notice IN 2010-12 – Containment Liner Corrosion. The NRC issued this IN to inform addressees of recent issues involving corrosion of the steel reactor containment building liner. The AR response addressed all the concerns identified by the IN 2010-12. The AR concludes that: i) Seabrook Station Containment structure is enclosed by a reinforced seismic category I concrete enclosure building which prevents exterior containment concrete from exposure to external atmosphere; ii) during construction at Seabrook Station there were three independent levels of Quality Control that provided assurance that adequate concrete placement techniques were implemented which eliminated the possibility of foreign material (organic compounds) being introduced during the concrete placement; and iii) the last IWE inspections of the containment liner performed at the Seabrook Station concluded that there were minor imperfections and discoloration in the coating film and isolated areas where the coating had been damaged, exposing the liner steel which contained only rust staining or minor surface corrosion. In general, there was no measurable corrosion or any metal loss detected in the containment liner steel.

2. In October 2010 an AR identified failure and degradation of Reactor Sump Liner Coating of the Unit 3 Reactor Sump Liner Plate at Turkey Point Nuclear Station. NextEra is in the process of evaluating this current AR for applicability at Seabrook.

3. In December 1997, Condition Report (CR) identified containment liner paint (approximately two square feet) scraped off at the scaffold storage area during the refueling outage OR05, due to poor material control

practices for storing the scaffolding material. Paint in this area and other additional areas listed in the work order were repaired.

4. In July 1998 Seabrook personnel performed a review of NRC Generic Letter GL 98-04 – Potential for Degradation of the Emergency Core Cooling System (ECCS) and the Containment Spray System (CSS) After a Loss-of-Coolant (LOCA) Accident Because of Construction and Protective Coating Deficiencies and Foreign Material in Containment. Seabrook Station responded to GL 98-04 via letter NYN-98125.

5. In November 1997, during the responsible project engineer's evaluation of the IWE program for inspection of the containment liner indication, additional corrosion/paint flaking was discovered behind blocks 7 and 9 in containment at the -26' elevation. A work order was generated to perform visual inspection of the containment liner and also included the work activities for removing and replacing degraded moisture barrier, cleaning surface corrosion, and paint repair on the liner as required by the engineering evaluation. Ultrasonic thickness measurements were performed on the containment liner and the thickness was found to be satisfactory and the post-repair general visual exam was performed and found to be acceptable.

6. In December 2000, the containment liner paint was chipped at the 25' elevation in the stud rack storage area due to movement of reactor vessel stud racks (required for reactor vessel studs installation) during the refueling outage OR07. During OR07 the responsible engineer evaluated the affected area and identified several small nicks and dings that penetrated through the protective coatings down to the base metal. No adverse effect or any surface corrosion was identified on the containment liner by the responsible engineer. This area of the liner was cleaned, prepped and painted during the refueling outage OR08 as required by the responsible engineer's evaluation.

7. In October 2006, a Condition Report (CR) documented the results of containment coating closeout inspection per requirements of specification "S-S-1-E-0147, Protective Coatings for Service Level 1 Applications Inside the Containment Building". This inspection documented acceptance of the coating and identified required coating repairs (due to peeling and corrosion), and caulking repairs at various locations in the containment. This CR generated several work orders, which required: 1) painters to perform a walk down of the identified areas in the containment for paint repair, 2) prepping, sandblasting or stripping, and painting for stairways, ladders and several valves in the containment; (all activities were completed and accepted by nuclear oversight) and 3) location and repair of cracked/chipped paint on the

side of a trench at the CRDM Bridge (painters checked coating adhesion around this cracking with a dull putty knife and found no chipping or loosening of the coating).

The above examples provide objective evidence that when degraded/deteriorated Service Level I Coatings are identified, they are entered into the corrective action process so that corrective actions will be taken to address the issue. Appropriate guidance for evaluation, repair, or replacement is provided for locations where degraded/deteriorated Service Level I Coatings are identified. The previous examples of operating experience provide objective evidence that the Seabrook Station Protective Coating Monitoring and Maintenance Program will be effective in ensuring that intended function(s) will be maintained.

Conclusion

The Seabrook Station Protective Coating Monitoring and Maintenance Program provides reasonable assurance that those coatings managed by this program will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

<u>Enclosure 6 to SBK-L- 10192</u>

LRA Appendix A - Final Safety Report Supplement

Table A.3 License Renewal Commitment List

A.3 LICENSE RENEWAL COMMITMENT LIST

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
1.	PWR Vessel Internals	An inspection plan for Reactor Vessel Internals will be submitted for NRC review and approval at least twenty-four months prior to entering the period of extended operation.	A.2.1.7	Program to be implemented prior to the period of extended operation. Inspection plan to be submitted to NRC not less than 24 months prior to the period of extended operation.
2.	Closed-Cycle Cooling Water	Enhance the program to include visual inspection for cracking, loss of material and fouling when the in-scope systems are opened for maintenance.	A.2.1.12	Prior to the period of extended operation
3.	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the program to monitor general corrosion on the crane and trolley structural components and the effects of wear on the rails in the rail system.	A.2.1.13	Prior to the period of extended operation
4.	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Enhance the program to list additional cranes for monitoring.	A.2.1.13	Prior to the period of extended operation
5.	Compressed Air Monitoring	Enhance the program to include an annual air quality test requirement for the Diesel Generator compressed air sub system.	A.2.1.14	Prior to the period of extended operation
6.	Fire Protection	Enhance the program to perform visual inspection of penetration seals by a fire protection qualified inspector.	A.2.1.15	Prior to the period of extended operation.

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
7.	Fire Protection	Enhance the program to add inspection requirements such as spalling, and loss of material caused by freeze-thaw, chemical attack, and reaction with aggregates by qualified inspector.	A.2.1.15	Prior to the period of extended operation.
8.	Fire Protection	Enhance the program to include the performance of visual inspection of fire-rated doors by a fire protection qualified inspector.	A.2.1.15	Prior to the period of extended operation.
9.	Fire Water System	Enhance the program to include NFPA 25 guidance for "where sprinklers have been in place for 50 years, they shall be replaced or representative samples from one or more sample areas shall be submitted to a recognized testing laboratory for field service testing".	A.2.1.16	Prior to the period of extended operation.
10.	Fire Water System	Enhance the program to include the performance of periodic flow testing of the fire water system in accordance with the guidance of NFPA 25.	A.2.1.16	~~Within ten years of entering the period of extended operation~~. ***Prior to the period of extended operation.***
11.	Fire Water System	Enhance the program to include the performance of periodic visual inspection of the internal surface of the fire protection system upon each entry to the system for routine or corrective maintenance. ~~This~~ ***These*** inspection***s*** will be performed ~~no earlier than 10 years before~~ ***within ten years prior*** **to** the period of extended operation.	A.2.1.16	~~Prior~~ ***Within ten years prior*** to the period of extended operation.
12.	Aboveground Steel Tanks	Enhance the program to include components and aging effects required by the Aboveground Steel Tanks.	A.2.1.17	Prior to the period of extended operation.

13.	Aboveground Steel Tanks	Enhance the program to include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks.	A.2.1.17	~~Within ten years of entering the period of extended operation.~~ ***Within ten years prior to the period of extended operation.***
14.	Fuel Oil Chemistry	Enhance program to add requirements to 1) sample and analyze new fuel deliveries for biodiesel prior to offloading to the Auxiliary Boiler fuel oil storage tank and 2) periodically sample stored fuel in the Auxiliary Boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
15.	Fuel Oil Chemistry	Enhance the program to add requirements to check for the presence of water in the Auxiliary Boiler fuel oil storage tank at least once per quarter and to remove water as necessary.	A.2.1.18	Prior to the period of extended operation.
16.	Fuel Oil Chemistry	Enhance the program to require draining, cleaning and inspection of the diesel fire pump fuel oil day tanks on a frequency of at least once every ten years.	A.2.1.18	Prior to the period of extended operation.
17.	Fuel Oil Chemistry	Enhance the program to require ultrasonic thickness measurement of the tank bottom during the 10-year draining, cleaning and inspection of the Diesel Generator fuel oil storage tanks, Diesel Generator fuel oil day tanks, diesel fire pump fuel oil day tanks and auxiliary boiler fuel oil storage tank.	A.2.1.18	Prior to the period of extended operation.
18.	Reactor Vessel Surveillance	Enhance the program to specify that all pulled and tested capsules, unless discarded before August 31, 2000, are placed in storage.	A.2.1.19	Prior to the period of extended operation.
19.	Reactor Vessel Surveillance	Enhance the program to specify that if plant operations exceed the limitations or bounds defined by the Reactor Vessel Surveillance Program, such as operating at a lower cold leg temperature or higher fluence, the impact of plant operation changes on the extent of Reactor	A.2.1.19	Prior to the period of extended operation.

		Vessel embrittlement will be evaluated and the NRC will be notified.		
20.	Reactor Vessel Surveillance	Enhance the program as necessary to ensure the appropriate withdrawal schedule for capsules remaining in the vessel such that one capsule will be withdrawn at an outage in which the capsule receives a neutron fluence that meets the schedule requirements of 10 CFR 50 Appendix H and ASTM E185-82 and that bounds the 60-year fluence, and the remaining capsule(s) will be removed from the vessel unless determined to provide meaningful metallurgical data.	A.2.1.19	Prior to the period of extended operation.
21.	Reactor Vessel Surveillance	Enhance the program to ensure that any capsule removed, without the intent to test it, is stored in a manner which maintains it in a condition which would permit its future use, including during the period of extended operation.	A.2.1.19	Prior to the period of extended operation.
22.	One-Time Inspection	Implement the One Time Inspection Program.	A.2.1.20	~~Within ten years of entering the period of extended operation.~~ ***Within ten years prior to the period of extended operation.***
23.	Selective Leaching of Materials	Implement the Selective Leaching of Materials Program.	A.2.1.21	~~Within five years of entering the period of extended operation.~~ ***Within five years prior to the period of extended operation.***
24.	Buried Piping And Tanks Inspection	Implement the Buried Piping And Tanks Inspection Program.	A.2.1.22	Within ten years prior to entering the period of extended operation

25.	One-Time Inspection of ASME Code Class 1 Small Bore-Piping	Implement the One-Time Inspection of ASME Code Class 1 Small Bore-Piping Program.	A.2.1.23	~~Within ten years of entering the period of extended operation.~~ ***Within ten years prior to the period of extended operation.***
26.	External Surfaces Monitoring	Enhance the program to specifically address the scope of the program, relevant degradation mechanisms and effects of interest, the refueling outage inspection frequency, the inspections of opportunity for possible corrosion under insulation, the training requirements for inspectors and the required periodic reviews to determine program effectiveness.	A.2.1.24	Prior to the period of extended operation.
27.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Implement the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components Program.	A.2.1.25	Prior to the period of extended operation.
28.	Lubricating Oil Analysis	Enhance the program to add required equipment, lube oil analysis required, sampling frequency, and periodic oil changes.	A.2.1.26	Prior to the period of extended operation.
29.	Lubricating Oil Analysis	Enhance the program to sample the oil for the Switchyard SF_6 compressors and the Reactor Coolant pump oil collection tanks.	A.2.1.26	Prior to the period of extended operation.
30.	Lubricating Oil Analysis	Enhance the program to require the performance of a one-time ultrasonic thickness measurement of the lower portion of the Reactor Coolant pump oil collection tanks prior to the period of extended operation.	A.2.1.26	Prior to the period of extended operation.
31.	ASME Section XI, Subsection IWL	Enhance procedure to include the definition of "Responsible Engineer".	A.2.1.28	Prior to the period of extended operation.

32.	Structures Monitoring Program	Enhance procedure to add the aging effects, additional locations, inspection frequency and ultrasonic test requirements.	A.2.1.31	Prior to the period of extended operation.
33.	Structures Monitoring Program	Enhance procedure to include inspection of opportunity when planning excavation work that would expose inaccessible concrete.	A.2.1.31	Prior to the period of extended operation.
34.	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.32	Prior to the period of extended operation.
35.	Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Implement the Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program.	A.2.1.33	Prior to the period of extended operation.
36.	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.34	Prior to the period of extended operation.
37.	Metal Enclosed Bus	Implement the Metal Enclosed Bus program.	A.2.1.35	Prior to the period of extended operation.
38.	Fuse Holders	Implement the Fuse Holders program.	A.2.1.36	Prior to the period of extended operation.
39.	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Implement the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.	A.2.1.37	Prior to the period of extended operation.

40.	345 KV SF_6 Bus	Implement the 345 KV SF_6 Bus program.	A.2.2.1	Prior to the period of extended operation.
41.	Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to include additional transients beyond those defined in the Technical Specifications and UFSAR.	A.2.3.1	Prior to the period of extended operation.
42.	Metal Fatigue of Reactor Coolant Pressure Boundary	Enhance the program to implement a software program, to count transients to monitor cumulative usage on selected components.	A.2.3.1	Prior to the period of extended operation.
43.	Pressure –Temperature Limits, including Low Temperature Overpressure Protection Limits	Seabrook Station will submit updates to the P-T curves and LTOP limits to the NRC at the appropriate time to comply with 10 CFR 50 Appendix G.	A.2.4.1.4	The updated analyses will be submitted at the appropriate time to comply with 10 CFR 50 Appendix G, Fracture Toughness Requirements.
44.	Environmentally-Assisted Fatigue Analyses (TLAA)	(1) Consistent with the Metal Fatigue of Reactor Coolant Pressure Boundary Program Seabrook Station will update the fatigue usage calculations using refined fatigue analyses, if necessary, to determine acceptable CUFs (i.e., less than 1.0) when accounting for the effects of the reactor water environment. This includes applying the appropriate F_{en} factors to valid CUFs determined from an existing fatigue analysis valid for the period of extended operation or from an analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case). (2) If acceptable CUFs cannot be demonstrated for all the selected locations, then additional plant-specific locations will be evaluated. For the additional plant-specific locations, if CUF, including environmental effects is greater than 1.0, then Corrective Actions will be initiated, in accordance with the Metal Fatigue of Reactor Coolant Pressure Boundary Program, B.2.3.1. Corrective Actions will include inspection, repair, or replacement of the affected locations before exceeding a CUF of 1.0 or the effects of fatigue will be managed by an inspection program that has been reviewed and approved by the	A.2.4.2.3	At least two years prior to entering the period of extended operation.

		NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).		
45.	Mechanical Equipment Qualification	Revise Mechanical Equipment Qualification Files.	A.2.4.5.9	Prior to the period of extended operation.
46.	***Protective Coating Monitoring and Maintenance***	***Enhance the program by designating and qualifying an Inspector Coordinator and an Inspection Results Evaluator.***	***A.2.1.38***	***Prior to the period of extended operation***
47.	***Protective Coating Monitoring and Maintenance***	***Enhance the program by including, "Instruments and Equipment needed for inspection may include, but not be limited to, flashlight, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide angle lens, and self sealing polyethylene sample bags."***	***A.2.1.38***	***Prior to the period of extended operation***
48.	***Protective Coating Monitoring and Maintenance***	***Enhance the program to include a review of the previous two monitoring reports.***	***A.2.1.38***	***Prior to the period of extended operation***
49.	***Protective Coating Monitoring and Maintenance***	***Enhance the program to require that the inspection report is to be evaluated by the responsible evaluation personnel, who is to prepare a summary of findings and recommendations for future surveillance or repair.***	***A.2.1.38***	***Prior to the period of extended operation***