NEXTera® ENERGY SEABROOK

November 23, 2016

10 CFR 54
SBK-L-16186
Docket No. 50-443

U. S. Nuclear Regulatory Commission
Attn: Document Control Desk
Washington, DC 20555-0001

Seabrook Station
Supplement 50 - Response to Requests for Additional Information for the Review of the Seabrook Station License Renewal Application (CAC NO. ME4028) – Changes to Buried and Underground Piping and Tank Recommendations

References:

1. NextEra Energy Seabrook LLC, letter SBK-L-10077, "Seabrook Station Application for Renewed Operating License," May 25, 2010 (Accession Number ML10150099).
2. License Renewal Interim Staff Guidance, LR-ISG-2015-01 "Changes to Buried and Underground Piping and Tank Recommendations."
3. NextEra Energy Seabrook, LLC letter SBK-L-16156, "Response to Issuance of LR-ISG-2015-01, Changes to Buried and Underground Piping and Tank Recommendations," October 07, 2016 (Accession Number ML16286A631).
4. NRC, "Requests for Additional Information for the Review of the Seabrook Station License Renewal Application (CAC NO. ME4028);" November 14, 2016 (Accession Number ML16301A428).

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In Reference 1, NextEra Energy Seabrook submitted an application for a renewed facility operating license for Seabrook Station Unit 1 in accordance with the Code of Federal Regulations, Title 10, Parts 50, 51, and 54.

In Reference 2, the NRC issued License Renewal Interim Staff Guidance, LR-ISG-2015-01 – Changes to Buried and Underground Piping and Tank Recommendations. The guidance provided within this ISG was utilized to develop the NextEra Energy Seabrook's Buried Piping and Tanks Inspection Aging Management Program.

In Reference 3, NextEra Energy provided the Staff with letter SBK-L-16156, "Response to Issuance of LR-ISG-2015-01, Changes to Buried and Underground Piping and Tank Recommendations."

In Reference 4, the NRC requested additional information related to the latest Buried and Underground Piping and Tank Aging Management Program submittal (Reference 3). Enclosure 1 provides the responses to the request for additional information.

Provided in this Supplement are changes to the LRA. To facilitate understanding, the changes are explained, and where appropriate, portions of the LRA are repeated with the change highlighted by strikethroughs for deleted text and bolded italics for inserted text.

This letter contains one revised Commitment, #64. Enclosure 2 provides the revised LRA Appendix A - Updated Final Safety Analysis Report Supplement Table A.3, License Renewal Commitment List.

If there are any questions or additional information is needed, please contact Mr. Edward J. Carley, Engineering Supervisor - License Renewal, at (603) 773-7957.

If you have any questions regarding this correspondence, please contact Mr. Kenneth Browne, Licensing Manager, at (603) 773-7932.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on November 23 , 2016.

Sincerely,

NextEra Energy Seabrook, LLC

Eric McCartney
Site Vice President

Enclosures

Enclosure 1: NextEra Energy Seabrook's Response to Requests for Additional Information for the Review of the Seabrook Station License Renewal Application – Changes to Buried and Underground Piping and Tank Recommendations

Enclosure 2: LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List Update to Commitment #64, Soil Sampling Schedule

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Enclosure 1 to SBK-L-16186

NextEra Energy Seabrook's Response to Requests for Additional Information for the Review of the Seabrook Station License Renewal Application – Changes to Buried and Underground Piping and Tank Recommendations

RAI A.2.1.22-1

Background:

As amended by letter dated October 7, 2016, License Renewal Application (LRA) Section A.2.1.22, "Buried Piping and Tanks Inspection," (Updated Final Safety Analysis Report (UFSAR) summary description for the Buried Piping and Tanks Inspection program) was revised in response to the issuance of LR-ISG-2015-01, "Changes to Buried and Underground Piping and Tank Recommendations."

The UFSAR summary description issued in LR-ISG-2015-01 includes the following recommendations:

- The number of inspections is based on the effectiveness of the preventive and mitigative actions.
- Annual cathodic protection surveys are conducted.
- For steel components, where the acceptance criteria for the effectiveness of the cathodic protection is other than -850 mV instant off, loss of material rates are measured.
- Inspections are conducted by qualified individuals.
- Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted.
- If a reduction in the number of inspections recommended in GALL Report, AMP XI.M41, Table XI.M41-2 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing is conducted once in each 10-year period starting 10 years prior to the period of extended operation.

Issue:

The staff noted that aspects of the UFSAR summary description issued in LR-ISG-2015-01 (bulletized above) were not included in the revised LRA Section A.2.1.22. It is unclear to the staff why these aspects of the UFSAR summary description issued in LR-ISG-2015-01 were not included in the revised LRA Section A.2.1.22.

Request:

State the basis for not including aspects of the UFSAR Summary Description issued in LR-ISG-2015-01 (bulletized above) in the revised LRA Section A.2.1.22.

NextEra Energy Seabrook Response to RAI A.2.1.22-1

LRA Section A.2.1.22 has been revised to incorporate LR-ISG-2015-01, Appendix A, SRP-LR Table 3.0-1, FSAR Supplement for AMP XI.M41. Revisions to A.2.1.22 are shown below.

A.2.1.22 BURIED PIPING AND TANKS INSPECTION

The Buried Piping and Tanks Inspection Program ***is a condition monitoring program that*** manages ***the aging effects associated with*** ~~loss of material from~~ the external surfaces of buried, underground, and inaccessible submerged ***piping,*** ~~steel, stainless~~

~~steel, Copper Alloy (>15% Zinc), and polymer piping and components~~ ***such as loss of material, cracking, and changes in material properties. It addresses piping composed of steel, stainless steel, and polymer. Copper alloy (>15% zinc) components associated with inaccessible submerged Service Water piping are also within the scope of this program.*** The plant has no buried tanks in scope for license renewal.

Depending on the material, the program includes external coatings, cathodic protection, analyses for soil corrosivity, and quality of backfill as preventive ~~measures to mitigate~~ ***and mitigative actions*** ~~corrosion~~. ***The number of inspections is based on the effectiveness of the preventive and mitigative actions. Annual cathodic protection surveys are conducted. Steel components utilizing cathodic protection have an effectiveness acceptance criterion of -850 mV instant off.***

Inspections are conducted by qualified individuals. The program includes provisions for visual inspections of the protective wraps and coatings on buried steel and stainless steel piping. If damage to the protective wraps or coatings is found and the piping surface is exposed, the pipe is inspected for loss of material due to general, pitting, crevice or microbiologically-influenced corrosion. If corrosion has occurred, the wall thickness will be determined. ***Steel and*** stainless steel piping will be inspected for stress corrosion cracking using volumetric non-destructive examination techniques. Polymer piping is inspected for changes in material properties and for indication of cracking and blistering. ***Where the coatings, backfill or the condition of exposed piping does not meet acceptance criteria such that the depth or extent of degradation of the base metal could have resulted in a loss of pressure boundary function when the loss of material rate is extrapolated to the end of the period of extended operation, an increase in the sample size is conducted. If a reduction in the number of inspections recommended in the Buried Piping and Tanks Inspection Aging Management Plan, Table 3, is claimed based on a lack of soil corrosivity, as determined by soil testing, then soil testing is conducted once in each 10-year period starting 10 years prior to the period of extended operation.***

The program includes verification of the effectiveness of the cathodic protection system, non-destructive evaluation of the pipe wall thicknesses, ~~hydrostatic~~ ***pressure*** testing of the pipe, internal inspections, and monitoring of the fire protection system jockey pump operation.

This program also manages the aging effects (loss of material and loss of preload) of buried, underground, or inaccessible submerged piping system bolting.

RAI B.2.1.22-1

Background:

The following Request for Additional Information (RAI) addresses three staff identified inconsistencies within the LRA, warranting clarification.

1) GALL Report AMP XI.M41, Table XI.M41-2, as modified by LR-ISG-2015-01, states that in order to demonstrate that the soil is not corrosive, the applicant must obtain a minimum of ***three*** sets of soil samples in each soil environment in the vicinity in which in-scope components are buried.

As amended by letter dated October 7, 2016, the "detection of aging effects" program element of LRA Section B.2.1.22 states that soil samples will be taken at a minimum of ***two*** locations in the vicinity of in-scope, non-cathodically protected steel piping to obtain representative soil conditions for each system.

As amended by letter dated October 7, 2016, LRA Section B.2.1.22, Table 3, states that Seabrook will obtain a minimum of ***three*** sets of soil samples in each soil environment in the vicinity in which in-scope components are buried.

2) As amended by letter dated October 7, 2016, the "parameters monitored or inspected" program element of LRA Section B.2.1.22 states that steel will be inspected for loss of material and cracking due to stress corrosion cracking.

As amended by letter dated October 7, 2016, the "detection of aging effects" program element of LRA Section B.2.1.22 states that metallic piping is inspected for loss of material due to all forms of corrosion and, for stainless steel, cracking due to stress corrosion cracking.

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, states that inspections for cracking due to stress corrosion cracking for steel utilize a method that has been demonstrated to be capable of detecting cracking.

3) LRA Section A.2.1.22 states that the Buried Piping and Tanks Inspection program manages loss of material from the external surfaces of buried, underground, and inaccessible submerged steel, stainless steel, copper alloy >15% zinc, and polymer piping and components. In addition LRA Section B.2.1.22, Table 2, lists copper alloy >15% zinc.

The LRA Section B.2.1.22, "scope of program" program element states that the program is required to support the aging management activities for buried steel, stainless steel, polymeric piping, and inaccessible submerged steel piping. In addition, the LRA Section B.2.1.22 "monitoring and trending" program element states that results of previous inspections will be evaluated, and used to assess the condition of the external surfaces of other buried or underground steel, stainless steel and polymer components. Furthermore, the LRA Section B.2.1.22 "detection of aging effects" program element states pipe to soil potential and the cathodic protection current are monitored for steel piping.

Issue:

1) It is unclear to the staff, due to conflicting wording in the LRA, if two or three sets of soil samples will be obtained in each soil environment in the vicinity in which in-scope components are buried.

2) It is unclear to the staff, due to conflicting wording in the LRA, if steel components will be managed for loss of material and cracking, or loss of material.

3) It is unclear to the staff if copper alloy >15% zinc is included within the scope of the Buried Piping and Tanks Inspection program due to conflicting wording in the LRA.

Request:

1) Reconcile the apparent discrepancy between the quantities of soil samples that will be obtained in each soil environment in the vicinity in which in-scope components are buried. If two sets of soil samples in each soil environment in the vicinity in which in scope components are buried will be obtained, justify the adequacy of two sets of soil samples in lieu of three sets as recommended in GALL Report AMP XI.M41, Table XI.M41-2, as modified by LR-ISG-2015-01.

2) State if steel components will be managed for loss of material and cracking, or loss of material, and revise the LRA as appropriate. If steel components will only be managed for loss of material, justify why cracking will not be managed as recommended in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

3) State if copper alloy >15% zinc is included within the scope of the Buried Piping and Tanks Inspection program and revise the LRA as appropriate.

NextEra Energy Seabrook Response to RAI B.2.1.22-1

1) The following paragraph from B.2.1.22, Element 4 – Detection of Aging Effects, has been revised to address the discrepancy between the quantities of soil samples that will be obtained in each soil environment in the vicinity in which in-scope components are buried.

> Soil samples will be taken prior to entering the period of extended operation (PEO) to confirm that the soil conditions are not corrosive. The corrosivity of the soil will be used as a factor in determining the number of locations or percentage of piping to be inspected for non-cathodically protected steel piping. If the initial survey shows the soil to be non-corrosive, additional soil samples will be taken at least once every 10 years during the PEO to confirm the initial sample results. Soil samples will be taken at a minimum of ~~two~~ ***three*** locations in the vicinity of in-scope, non-cathodically protected steel piping to obtain representative soil conditions for each system (except for Fire Protection if the integrity of that system is monitored by jockey pump performance). The parameters monitored will be utilized to obtain a comparative corrosion index (corrosivity) for the piping within the systems monitored. Corrosivity will be determined using established soil analysis methodology such as EPRI Report 1021470, "Balance of Plant Corrosion - The Buried Pipe Reference Guide", Chapter 8, "Soil Analysis." The EPRI report arrives at a corrosion index using combined values for soil resistivity, pH, redox potential, sulfides, and moisture in accordance with American Water Works Association standard C105, and considers the soil to be corrosive if the combined value of 10 or greater.

2) B.2.1.22, Element 3 – Parameters Monitored or Inspected, has been revised to clarify that steel components will be managed for loss of material as well as cracking, and can be seen below.

ELEMENT 3 - Parameters Monitored or Inspected

Visual inspections of: (a) the external surface condition of buried or underground piping; (b) the external surface condition of associated coatings: (c) external surfaces of controlled low strength material backfill are performed. Monitoring of the surface condition of the component is conducted to ensure that the aging effects below are not present or have not progressed to such a degree where a loss of intended function could occur.

Visual inspections of the external surface condition of the component should detect:

- Loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion (MIC) for aluminum alloy (MIC is not applicable for aluminum alloys), copper alloy, steel, stainless steel, super austenitic, and titanium alloy components.

- Loss of material due to wear for polymeric materials.

- ***Cracking, blistering, change in color due to water absorption for high-density polyethylene and fiberglass components.***

~~Steel and stainless steel piping will be inspected for degradation of coating materials. Should damage or other degradation of coating materials so as to expose the base material be noted, the condition will be documented, evaluated, and corrected in accordance with the Seabrook Station corrective action program. When such damage or degradation of coating materials is found, the affected area will be visually inspected to detect loss of material by external corrosion by surface or volumetric non-destructive examination techniques to detect cracking due to stress corrosion cracking in stainless steel piping or loss of pipe wall thickness in stainless steel and steel piping.~~

~~Polymer piping will be inspected, by manual examinations, for changes in material properties, and by visual inspection for signs of cracking, blistering or damage. Any changes in material properties, or signs of cracking, blistering or damage, will be documented, evaluated, and, corrected in accordance with the Seabrook Station corrective action program.~~

~~Visual inspections of: (a) the external surface condition of buried or underground piping; (b) the external surface condition of associated coatings; or (c) external surfaces of controlled low strength material backfill are performed. Monitoring of the surface condition of the component is conducted to ensure that the aging effects are not present or have not progressed to such a degree where a loss of intended function could occur. Monitoring of the surface condition of coatings is conducted to ensure that the coatings are intact, well-adhered, and otherwise sound; such that aging effects would not be expected for the base material of the component. Monitoring of the external surfaces of controlled low strength material backfill is conducted to ensure that there are no cracks present that could admit groundwater to the surface of the component.~~

Volumetric nondestructive examination techniques as well as pit depth gages or calipers may be used for measuring wall thickness as long as: (a) they have been demonstrated

to be effective for the material, environment, and conditions (e.g., remote methods) during the examination; and (b) they are capable of quantifying general wall thickness and the depth of pits. Wall thickness measurements are conducted to ensure that minimum wall thickness requirements are met.

Inspections for cracking due to stress corrosion cracking for steel, stainless steel and susceptible aluminum alloy materials will utilize a method that has been demonstrated to be capable of detecting cracking. Coatings that: (a) are intact, well-adhered, and otherwise sound for the remaining inspection interval; and (b) exhibit small blisters that are few in number and completely surrounded by sound coating bonded to the substrate do not have to be removed. Inspections for cracking are conducted to assess the impact of cracks on the pressure boundary function of the component.

~~Two additional parameters, the~~ **P**ipe to soil potential and the cathodic protection current, will be monitored to determine the effectiveness of cathodic protection systems**.** ~~and, thereby, the effectiveness of corrosion mitigation.~~

This program provides an alternate means to test the integrity of the buried piping systems at Seabrook Station in lieu of external visual inspections. These alternate means are pressure testing, internal inspection, as well as flow testing, jockey pump monitoring, or annual system leakage rate testing of fire mains. These inspection and testing techniques have been demonstrated to provide reliable indication of the piping integrity, are preferable to excavation and visual inspection.

To credit pressure testing in lieu of visual inspection, at least 25% of the piping constructed from the material under consideration must be pressure tested to 110 percent of the design pressure of any component within the boundary with test pressure being held for eight hours and on an interval not to exceed 5 years. Such testing will identify boundary leakage in significantly larger portions of the respective piping system than excavation and visual inspection of coating integrity.

To credit internal inspection, at least 25% of the piping constructed from the material under consideration is internally inspected by a method capable of determining pipe wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be qualified by Seabrook Station and accepted by the NRC. Internal inspections are to be conducted at an interval not to exceed 10 years.

Fire mains may be excluded from the visual inspections if subjected to a flow test as described in section 7.3 of NFPA 25, at a frequency of at least one test in each one year period, or the jockey pump operation (e.g., pump starts, run time) is monitored for unexplained changes in pump activity at an interval not to exceed once a month.

At Seabrook Station, the fire protection jockey pump maintains the fire mains pressurized. Starts and running time of the fire protection jockey pumps are monitored and treated as an indicator of possible system leakage. This method of continuous monitoring of pressure losses in the fire mains will identify pipe boundary leakage in significantly larger portions of the fire protection piping system than excavation and visual inspection of coating integrity. At a minimum, a flow test will be conducted by the end of the next refueling outage or as directed by current licensing basis, whichever is shorter, when unexplained changes in jockey pump activity (or equivalent parameter) are observed.

This program also provides for management of the aging effects (loss of material) on buried, underground, and inaccessible submerged piping system bolting. Bolted connections in buried, underground, and inaccessible submerged piping will be inspected for indication of leakage caused by loss of preload when the associated piping is inspected by this program. In instances where pressure testing, flow testing, or fire protection jockey pump monitoring are used in lieu of visual inspections, these methods will also be credited to identify leakage caused by loss of preload at bolted connections.

Element 4 – Detection of Aging Effects, has also been revised to clarify that steel components will be managed for loss of material as well as cracking, and can be seen below.

The Seabrook Station Buried Piping and Tanks Program consists of inspection activities that are designed to detect degradation due to aging effects prior to loss of intended function. For buried and underground steel and stainless steel piping, opportunistic or directed visual inspections will be performed to confirm that coating and wrapping are intact. In the event that the coating has been compromised and bare metal exposed, ~~metallic~~ ***the*** piping is inspected for loss of material***,*** ~~due to all forms of corrosion and, for stainless steel, cracking due to~~ and stress corrosion cracking ***utilizing a method that has been demonstrated to be capable of detecting cracking.*** Wall thickness is determined by a non-destructive examination technique such as ultrasonic testing (UT). For buried polymer piping, opportunistic or directed visual inspections are augmented with manual examinations to detect hardening, softening, or other changes in material properties.

3) The following changes to Element 1 – Scope of Program, Element 5 – Monitoring and Trending, and Element 4 – Detection of Aging Effects have been revised to reflect that components with a material of Copper Alloy >15% zinc are included within the scope of the Buried Piping and Tanks Inspection program.

<u>ELEMENT 1 - Scope of Program</u>

This program is used to manage the effects of aging for buried, underground, and inaccessible submerged piping within the scope of license renewal. The program addresses aging effects such as loss of material, cracking, and changes in material properties.

The Seabrook Station Buried Piping and Tanks Inspection Program includes (a) preventive measures to mitigate corrosion and (b) inspections to manage aging effects on in-scope piping. This program requires opportunistic or directed inspection of each piping material within the scope of this program be performed within ten years prior to entering the period of extended operation. Periodic inspections are performed every 10 years after entering the period of extended operation.

Loss of material due to corrosion of buried, underground, and inaccessible submerged piping system bolting within the scope of license renewal is managed using this program. This program will also manage loss of preload in pressure retaining bolting within the scope of this program by visual inspection for evidence of leakage when the associated piping is inspected by this program.

The program is required to support the aging management activities for buried steel, stainless steel, polymeric piping, ***copper alloy (>15% zinc),*** and inaccessible submerged steel piping. The following systems are within the scope of license renewal, and have components that are age managed by this program;

- AB Auxiliary Boiler
- ASC Auxiliary Steam Condensate
- ASH Auxiliary Steam Heating
- CBA Control Building Air Handling
- CO Condensate
- DF Plant Floor Drain
- DG Diesel Generator
- IA Instrument Air
- FW Feedwater
- FP Fire Protection
- SW Service Water

Implementation of the final design change replacing the piping associated with the above-ground fuel oil storage tank will be completed prior to the period of extended operation. The design for buried portions of the system will include a pipe-within-pipe configuration with leak detection capability. Portions of that buried piping that are in-scope for license renewal will be included in the Seabrook Station Buried Piping and Tanks Inspection Program. Portions of that final design that are above-ground, including tanks, will be evaluated in accordance with the License Renewal Rule, 10 CFR 54, and age managed under the appropriate programs through the period of extended operation

ELEMENT 5 - Monitoring and Trending

The results of previous inspections will be evaluated~~,~~ and used to assess the condition of ~~the external surfaces of~~ other buried***,*** ~~or~~ underground***, or inaccessible submerged*** steel, stainless steel, ~~and~~ polymer***ic, and copper alloy (>15% zinc)*** components~~,~~***;*** and to identify susceptible locations that may warrant further inspections.

2nd Paragraph of ELEMENT 4 - Detection of Aging Effects

Pipe to soil potential and the cathodic protection current are monitored for steel piping in contact with soil to determine the effectiveness of cathodic protection systems and, thereby, the effectiveness of corrosion mitigation. **There is no cathodic protection for in scope copper alloy (>15% zinc) material as there are only in-scope components, not piping. Drain valves on the spools in the Service Water vault and valve pit are constructed of aluminum bronze (categorized as "copper alloy >15% zinc") with aluminum bronze body to bonnet bolting. These components will be inspected for loss of material when the respective Service Water spool piping is inspected by this program.**

RAI B.2.1.22-2

Background:

As amended by letter dated October 7, 2016, the "acceptance criteria" program element of LRA Section B.2.1.22 states that cracking or blistering of polymer piping and unexplained changes in jockey pump activity are evaluated under the corrective action program.

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, states that acceptance criteria associated with this AMP are cracking is absent in rigid polymeric components and changes in jockey pump activity that cannot be attributed to leakage are not occurring.

Issue: It is unclear to the staff why cracking of polymer piping and unexplained changes in jockey pump activity are evaluated under the corrective action program in lieu of being not acceptable.

Request: State the basis for why cracking of polymer piping and unexplained changes in jockey pump activity are evaluated under the corrective action program in lieu of being not acceptable as recommended in GALL Report AMP XI.M41, as modified by LR-ISG-2015-01.

NextEra Energy Seabrook Response to B.2.1.22-2

Element 6 – Acceptance Criteria, has been revised to address this request and changes can be seen below.

ELEMENT 6 - Acceptance Criteria

For coated piping, there should be either no evidence of coating degradation or the type and extent of coating degradation should be insignificant as evaluated by an individual possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification, or an individual who has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Rev. 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.".

Where damage to the coating has been evaluated as significant and the damage was caused by non-conforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation. Any coating and wrapping degradation will be documented and evaluated under the corrective action program. Where the protective coating consists of paint with no other coating or wrapping (e.g., drop-out spools in the Service Water vault), inspection of the painted surface should confirm no evidence of coating degradation (exposed metal) or degradation of the pipe surface due to corrosion.

~~Cracking or blistering of polymer piping is evaluated under the corrective action program.~~

Cracking is absent in rigid polymeric components. Blistering, gouges, or wear of nonmetallic piping is evaluated.

Criteria for pipe to soil potential when using a saturated copper/copper sulfate reference electrode for steel piping is -850 mV relative to a CSE, instant off. To prevent damage to the coating, the limiting critical potential should not be more negative than -1200 mV.

Alternatives to the -850 mV criterion for steel piping include the following:

- 100 mV minimum polarization.
- -750 mV relative to a CSE, instant off where soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm.
- -650 mV relative to a CSE, instant off where soil resistivity is greater than 100,000 ohm-cm.
- Verify less than 1 mpy loss of material. Loss of material rates in excess of 1 mpy may be acceptable if an engineering evaluation demonstrates that the corrosion rate would not result in a loss of intended function prior to the end of the period of extended operation.

When using the 100 mV, -750 mV, or -650 mV polarization criteria as an alternative to the -850 mV criterion for steel piping, means to verify the effectiveness of the protection of the most anodic metal is incorporated into the program. One acceptable means to verify the effectiveness of the cathodic protection system, or to demonstrate that the loss of material rate is acceptable, is to use installed electrical resistance corrosion rate probes. The external loss of material rate is verified:

- Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.
- Every 2 years when using the 100 mV minimum polarization.
- Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.

As an alternative to verifying the effectiveness of the cathodic protection system every 5 years, soil resistivity testing is conducted annually during a period of time when the soil resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of 10 annual consecutive soil samples, soil resistivity testing can be extended to every 5 years if the results of the soil sample tests consistently verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, all soil resistivity values were greater than 10,000 ohm-cm).

When electrical resistance corrosion rate probes will be used, the application identifies:

- The qualifications of the individuals that will determine the installation locations of the probes and the methods of use (e.g., NACE CP4, "Cathodic Protection Specialist").

- How the impact of significant site features (e.g., large cathodic protection current collectors, shielding due to large objects located in the vicinity of the protected piping) and local soil conditions will be factored into placement of the probes and use of probe data. Soil corrosivity is determined by soil analysis. If the calculated corrosion index value is greater than 10 points (i.e., corrosive soil) the number of inspection locations for non-cathodically protected steel piping is increased as shown in Element 4 above.

Backfill is consistent with SP0169-2007 section 5.2.3. Backfill located within 6 inches of steel and stainless steel pipe that meets ASTM D 448-08 size number 67 meets the objectives of SP0169-2007. Backfill located within 6 inches of polymeric pipe that meets ASTM D 448-08 size number 10 meets the objectives of SP0169-2007. Backfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections conducted in accordance with this program. Backfill not meeting this standard, in either the initial or subsequent inspections, is acceptable if the inspections conducted in accordance with this program do not reveal evidence of mechanical damage to pipe coatings due to the backfill.

Flow test results for fire mains, if credited in lieu of visual inspections, are in accordance with NFPA 25 section 7.3.

Changes in jockey pump activity (or similar parameter) that cannot be attributed to causes other than leakage from buried piping are not occurring.

~~Unexplained changes in jockey pump activity (or similar parameter), if credited in lieu of visual inspections, are evaluated under the corrective action program.~~

When fire water system leak rate testing is conducted, leak rates are within acceptance limits of plant-specific documents.

For pressure tests, the test acceptance criteria is no visible indications of leakage and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or quantified leakage across test boundary valves.

Evaluation of all adverse indications (e.g., leaks, cracks, material thickness less than minimum, coarse backfill with accompanying coating degradation, and general or local degradation of coatings so as to expose the base material) is conducted in accordance with the corrective action program. Any expansion of the inspection sample size is one facet of this evaluation when determining extent of condition.

If coated or uncoated metallic piping or tanks show evidence of corrosion, the remaining wall thickness in the affected area is determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness, and local area wall thickness.

Measured wall thickness projected to the end of the period of extended operation meets minimum wall thickness requirements, or proper corrective actions are in place prior to reaching the projected minimum wall thickness requirements.

RAI B.2.1.22-3

Background:

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, states that Inspection Category D may be used for those portions of in-scope buried piping where it has been demonstrated, in accordance with the "preventive actions" program element of this Aging Management Program (AMP), that external corrosion control is not required.

As amended by letter dated October 7, 2016, the "detection of aging effects" program element of LRA Section B.2.1.22 cites inspection Category D.

Issue:

While the submittal describes soil conditions, it is unclear to the staff how inspection Category D is applicable given that other key parameters are not described (e.g., pipe to soil potential measurements) to demonstrate external corrosion control is not required for those portions of in-scope buried piping claiming to meet inspection Category D.

Request:

State the basis for how inspection Category D is applicable for those portions of in-scope buried piping where the applicant claims that external corrosion control is not required.

NextEra Energy Seabrook Response to RAI B.2.1.22-3

NextEra Energy Seabrook will not be utilizing Inspection Category D as described within Section 4 – Detection of Aging Effects within LR-ISG-2015-01. Tables 2 and 3 within B.2.1.22 have been revised to reflect this change and can be seen below.

Directed Inspections – Inaccessible Submerged Pipe

The number of inspections required during each 10 year interval is shown in the tables below. With the exception of backfill and soil resistivity criteria, inaccessible submerged piping will be inspected to the same extent as buried piping. The aluminum bronze drain valves attached to these piping segments will also be inspected for loss of material when the associated pipe segment is inspected.

Table 2 - Inspections of Buried, Underground Piping and Inaccessible Submerged Piping

Material	Prevention Action Categories	Inspections [1,2]	Systems Currently in Category
Stainless Steel		1 Inspection	CO, DG
Polymeric	Backfill is in accordance with preventive actions program element [3]	1 Inspection	FP

Table 2 - Inspections of Buried, Underground Piping and Inaccessible Submerged Piping			
	Backfill is not in accordance with preventive actions program category [3]	The smaller of 1% of the length of pipe or 2 inspections	
Steel	C	The smaller of 0.5% of the piping length or 1 inspection	CBA, IA, FP, SW [6], AB [4], CO, DF, DG, FW, ASC, ASH
	D	~~The smaller of 1% of the piping length or 2 inspections~~ ***N/A***	
	E	The smaller of 5% of the piping length or 3 inspections	
	F	The smaller of 10% of the piping length or 6 inspections	

Table 2 - Inspections of Buried, Underground Piping and Inaccessible Submerged Piping			
Copper Alloy >15% Zinc	C	The smaller of 0.5% of the piping length or 1 inspection	SW [7]
	D	~~The smaller of 1% of the piping length or 2 inspections~~ ***N/A***	
	E	The smaller of 5% of the piping length or 3 inspections	
	F	The smaller of 10% of the piping length or 6 inspections	

GENERAL NOTES:

1. When the inspections are based on the number of inspections in lieu of percentage of piping length, 10 feet of piping is exposed for each inspection.
2. When the percentage of inspections for a given material type results in an inspection quantity of less than 10 feet, then 10 feet of piping is inspected. If the entire run of piping of that material type is less than 10 feet in total length, then the entire run of piping is inspected.
3. The adequacy of backfill will be determined by the condition of coatings and base materials noted during inspections. If damage to the coatings or base materials is determined to have been caused by the backfill, the backfill will be considered to be "inadequate" (for the purpose of this program).
4. This line is not in use. It has been drained and flushed and is awaiting replacement. The inspection criteria for the replacement piping will be determined based material selection, coating, cathodic protection, and quality of backfill.
5. If Fire Protection piping is inspected by excavation in lieu of by alternative testing (e.g., flow test, jockey pump monitoring), and the extent of examinations is not based on the percentage of piping in the material group, the Not-to-Exceed (NTE) value will be increased by 1 inspection, if normally less than 10, or 2 inspections, if normally 10 or greater.
6. The Service Water vault located north of the cooling tower contains four 24" lines approximately 15' long. The valve pit located north of the cooling tower contains one 32" line less than 10' long.
7. Drain valves on the spools in the Service Water vault and valve pit are constructed of aluminum bronze (categorized as "copper alloy >15% zinc") with aluminum bronze body to bonnet bolting. These components will be inspected for loss of material when the respective Service Water spool piping is inspected by this program.

Table 3 - Preventive Action Categories

C: Category C Applies when:

a. Cathodic protection was installed or refurbished 5 years prior to the end of the inspection period of interest; and

b. Cathodic protection has operated at least 85 percent of the time since either 10 years prior to the period of extended operation or since installation / refurbishment, whichever is shorter. Time periods in which the cathodic protection system is off-line for testing do not have to be included in the total non-operating hours; and

c. Cathodic protection has provided effective protection for buried piping as evidenced by meeting the acceptance criteria in Section 3.6 of this AMP at least 80 percent of the time since either 10 years prior to the period of extended operation or since installation/refurbishment, whichever is shorter. As found results of annual surveys are to be used to demonstrate locations within the plant's population of buried pipe where cathodic protection acceptance criteria have, or have not, been met.

D: ~~Inspection criteria provided for Category D piping may be used for those portions of in-scope buried piping where it has been demonstrated, in accordance with the "preventive actions" program element of this AMP, that external corrosion control is not required.~~ **Inspection Category D will not be used.**

E: Inspection criteria provided for Category E piping may be used for those portions of the population of buried piping where:

a. An analysis, conducted in accordance with the "preventive actions" program element of this AMP, has demonstrated that installation or operation of a cathodic protection system is impractical; or

b. A cathodic protection system has been installed but all or portions of the piping covered by that system fail to meet any of the criteria of Category C piping above, provided:

   i. Coatings and backfill are provided in accordance with the "preventive actions" program element of this AMP; and

   ii. Plant-specific operating experience is acceptable (i.e., no leaks in buried piping due to external corrosion, no significant coating degradation or metal loss in more than 10 percent of inspections conducted); and

iii. Soil has been demonstrated to not be corrosive for the material type (e.g., AWWA C105, "Polyethylene Encasement for Ductile-Iron Pipe Systems," Table A.1, "Soil-Test Evaluation"). In order to demonstrate that the soil is not corrosive,

Seabrook will:

1) Obtain a minimum of three sets of soil samples in each soil environment (e.g., moisture content, soil composition) in the vicinity in which in-scope components are buried.

2) Tests the soil for soil resistivity, corrosion accelerating bacteria, pH, moisture, chlorides, sulfates, and redox potential.

3) Determines the potential soil corrosivity for each material type of buried in-scope piping. In addition to evaluating each individual parameter, the overall soil corrosivity is determined.

4) Conduct soil testing once in each 10-year period starting 10 years prior to the period of extended operation.

F: Inspection criteria provided for Category F piping is used for those portions of in-scope buried piping which cannot be classified as Category C, D, or E (e.g. Buried or Underground piping that do not meet recommendations within the Preventive Action Table 1).

RAI B.2.1.22-4

Background:

GALL Report AMP XI.M41, as modified by LR-ISG-2015-01, states that when electrical resistance corrosion rate probes will be used, the application identifies:

1) The qualifications of the individuals that will determine the installation locations of the probes and the methods of use (e.g., NACE CP4, "Cathodic Protection Specialist").

2) How the impact of significant site features (e.g., large cathodic protection current collectors, shielding due to large objects located in the vicinity of the protected piping), and local soil conditions will be factored into placement of the probes and use of probe data.

As amended by letter dated October 7, 2016, the "acceptance criteria" program element of LRA Section B.2.1.22 states that soil corrosivity is determined by soil analysis and that if the calculated corrosion index value is greater than 10 points (i.e., corrosive soil) the number of inspection locations for non-cathodically protected steel piping is increased.

Issue:

The staff noted that the submittal did identify how local soil conditions will be factored into placement of the probes and use of probe data; however it did not address:

(1) The qualifications of the individuals that will determine the installation locations of the probes and the methods of use.

(2) How the impact of significant site features will be factored into the placement of the probes and use of probe data.

Request:

Provide additional information to address the two issues noted above regarding the use of electrical resistance corrosion rate probes.

NextEra Energy Seabrook Response to RAI .2.1.22-4

NextEra Energy Seabrook plans to utilize the -850 mV criterion for steel piping, and to not implement the use of electrical resistance corrosion rate probes as an alternative to this criterion. Aging Management Program B.2.1.22, Element 6 – Acceptance Criteria, is revised as follows.

ELEMENT 6 - Acceptance Criteria

> For coated piping, there should be either no evidence of coating degradation or the type and extent of coating degradation should be insignificant as evaluated by an individual possessing a NACE Coating Inspector Program Level 2 or 3 inspector qualification, or an individual who has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course, or a coatings specialist qualified in accordance with an ASTM standard endorsed in Regulatory Guide 1.54, Rev. 2, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants.".

Where damage to the coating has been evaluated as significant and the damage was caused by non-conforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation. Any coating and wrapping degradation will be documented and evaluated under the corrective action program. Where the protective coating consists of paint with no other coating or wrapping (e.g., drop-out spools in the Service Water vault), inspection of the painted surface should confirm no evidence of coating degradation (exposed metal) or degradation of the pipe surface due to corrosion.

~~Cracking or blistering of polymer piping is evaluated under the corrective action program.~~

Cracking is absent in rigid polymeric components. Blistering, gouges, or wear of nonmetallic piping is evaluated.

Criteria for pipe to soil potential when using a saturated copper/copper sulfate reference electrode for steel piping is -850 mV relative to a CSE, instant off. To prevent damage to the coating, the limiting critical potential should not be more negative than -1200 mV.

~~Alternatives to the -850 mV criterion for steel piping include the following:~~

- ~~100 mV minimum polarization.~~
- ~~-750 mV relative to a CSE, instant off where soil resistivity is greater than 10,000 ohm-cm to less than 100,000 ohm-cm.~~
- ~~-650 mV relative to a CSE, instant off where soil resistivity is greater than 100,000 ohm-cm.~~
- ~~Verify less than 1 mpy loss of material. Loss of material rates in excess of 1 mpy may be acceptable if an engineering evaluation demonstrates that the corrosion rate would not result in a loss of intended function prior to the end of the period of extended operation.~~

~~When using the 100 mV, -750 mV, or -650 mV polarization criteria as an alternative to the -850 mV criterion for steel piping, means to verify the effectiveness of the protection of the most anodic metal is incorporated into the program. One acceptable means to verify the effectiveness of the cathodic protection system, or to demonstrate that the loss of material rate is acceptable, is to use installed electrical resistance corrosion rate probes. The external loss of material rate is verified:~~

- ~~Every year when verifying the effectiveness of the cathodic protection system by measuring the loss of material rate.~~
- ~~Every 2 years when using the 100 mV minimum polarization.~~
- ~~Every 5 years when using the -750 or -650 criteria associated with higher resistivity soils. The soil resistivity is verified every 5 years.~~

~~As an alternative to verifying the effectiveness of the cathodic protection system every 5 years, soil resistivity testing is conducted annually during a period of time when the soil~~

~~resistivity would be expected to be at its lowest value (e.g., maximum rainfall periods). Upon completion of 10 annual consecutive soil samples, soil resistivity testing can be extended to every 5 years if the results of the soil sample tests consistently verified that the resistivity did not fall outside of the range being credited (e.g., for the -750 mV relative to a CSE, instant off criterion, all soil resistivity values were greater than 10,000 ohm-cm).~~

~~When electrical resistance corrosion rate probes will be used, the application identifies:~~

- ~~The qualifications of the individuals that will determine the installation locations of the probes and the methods of use (e.g., NACE CP4, "Cathodic Protection Specialist").~~
- ~~How the impact of significant site features (e.g., large cathodic protection current collectors, shielding due to large objects located in the vicinity of the protected piping) and local soil conditions will be factored into placement of the probes and use of probe data. Soil corrosivity is determined by soil analysis. If the calculated corrosion index value is greater than 10 points (i.e., corrosive soil) the number of inspection locations for non-cathodically protected steel piping is increased as shown in Element 4 above.~~

Backfill is consistent with SP0169-2007 section 5.2.3. Backfill located within 6 inches of steel and stainless steel pipe that meets ASTM D 448-08 size number 67 meets the objectives of SP0169-2007. Backfill located within 6 inches of polymeric pipe that meets ASTM D 448-08 size number 10 meets the objectives of SP0169-2007. Backfill quality may be demonstrated by plant records or by examining the backfill while conducting the inspections conducted in accordance with this program. Backfill not meeting this standard, in either the initial or subsequent inspections, is acceptable if the inspections conducted in accordance with this program do not reveal evidence of mechanical damage to pipe coatings due to the backfill.

Flow test results for fire mains, if credited in lieu of visual inspections, are in accordance with NFPA 25 section 7.3.

Changes in jockey pump activity (or similar parameter) that cannot be attributed to causes other than leakage from buried piping are not occurring.

~~Unexplained changes in jockey pump activity (or similar parameter), if credited in lieu of visual inspections, are evaluated under the corrective action program.~~

When fire water system leak rate testing is conducted, leak rates are within acceptance limits of plant-specific documents.

For pressure tests, the test acceptance criteria is no visible indications of leakage and no drop in pressure within the isolated portion of the piping that is not accounted for by a temperature change in the test media or quantified leakage across test boundary valves.

Evaluation of all adverse indications (e.g., leaks, cracks, material thickness less than minimum, coarse backfill with accompanying coating degradation, and general or local degradation of coatings so as to expose the base material) is conducted in accordance with the corrective action program. Any expansion of the inspection sample size is one facet of this evaluation when determining extent of condition.

If coated or uncoated metallic piping or tanks show evidence of corrosion, the remaining wall thickness in the affected area is determined to ensure that the minimum wall thickness is maintained. This may include different values for large area minimum wall thickness, and local area wall thickness.

Measured wall thickness projected to the end of the period of extended operation meets minimum wall thickness requirements, or proper corrective actions are in place prior to reaching the projected minimum wall thickness requirements.

Enclosure 2 to SBK-L-16186

LRA Appendix A - Final Safety Report Supplement Table A.3, License Renewal Commitment List Update to Commitment #64, Soil Sampling Schedule

A.3 LICENSE RENEWAL COMMITMENT LIST

No.	PROGRAM or TOPIC	COMMITMENT	UFSAR LOCATION	SCHEDULE
1.	PWR Vessel Internals	Provide confirmation and acceptability of the implementation of MRP-227-A by addressing the plant-specific Applicant/Licensee Action Items outlined in section 4.2 of the NRC SER.	A.2.1.7	Complete
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.
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 (2011 Edition) 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 (2011 Edition).	A.2.1.16	Prior to the period of extended operation.
11.	Fire Water System	Enhance the program to include the performance of periodic visual or volumetric inspection 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 ensuring that corrosion product buildup will not result in flow blockage due to fouling. Where surface irregularities are detected, follow-up volumetric examinations are performed. These inspections will be documented and trended to determine if a representative number of inspections have been performed prior to the period of extended operation. If a representative number of inspections have not been performed prior to the period of extended operation, focused inspections will be conducted. These inspections will commence during the ten year period prior to the period of extended operation and continue through the period of extended operation	A.2.1.16	Within ten years prior to the period of extended operation.

12.	Aboveground Steel Tanks	Enhance the program to include 1) In-scope outdoor tanks, except fire water storage tanks, constructed on soil or concrete, 2) Indoor large volume storage tanks (greater than 100,000 gallons) designed to near-atmospheric internal pressures, sit on concrete or soil, and exposed internally to water, 3) Visual, surface, and volumetric examinations of the outside and inside surfaces for managing the aging effects of loss of material and cracking, 4) External visual examinations to monitor degradation of the protective paint or coating, and 5) Inspection of sealant and caulking for degradation by performing visual and tactile examination (manual manipulation) consisting of pressing on the sealant or caulking to detect a reduction in the resiliency and pliability.	A.2.1.17	Within 10 years prior to the period of extended operation.
13.	Fire Water System	Enhance the program to perform exterior inspection of the fire water storage tanks annually for signs of degradation and include an ultrasonic inspection and evaluation of the internal bottom surface of the two Fire Protection Water Storage Tanks per the guidance provided in NFPA 25 (2011 Edition).	A.2.1.16	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 Vessel embrittlement will be evaluated and the NRC will be notified.	A.2.1.19	Prior to the period of extended operation.
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 prior to the period of extended operation.
23.	Selective Leaching of Materials	Implement the Selective Leaching of Materials Program. The program will include a one-time inspection of selected components where selective leaching has not been identified and periodic inspections of selected components where selective leaching has been identified.	A.2.1.21	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 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 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 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 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 SF6 Bus	Implement the 345 KV SF6 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)	NextEra Seabrook will perform a review of design basis ASME Class 1 component fatigue evaluations to determine whether the NUREG/CR-6260-based components that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting components for the Seabrook plant configuration. If more limiting components are identified, the most limiting component will be evaluated for the effects of the reactor coolant environment on fatigue usage. If the limiting location identified consists of nickel alloy, the environmentally-assisted fatigue calculation for nickel alloy will be performed using the rules of NUREG/CR-6909. (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 Fen 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 NRC (e.g., periodic non-destructive examination of the affected locations at inspection intervals to be determined by a method accepted by the NRC).	A.2.4.2.3	At least two years prior to the period of extended operation.

45.	Number Not Used			
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.
50.	ASME Section XI, Subsection IWE	Perform UT of the accessible areas of the containment liner plate in the vicinity of the moisture barrier for loss of material. Perform opportunistic UT of inaccessible areas.	A.2.1.27	Baseline inspections were completed during OR16. Repeat containment liner UT thickness examinations at intervals of no more than five (5) refueling outages.
51.	Number Not Used			
52.	ASME Section XI, Subsection IWL	Implement measures to maintain the exterior surface of the Containment Structure, from elevation -30 feet to +20 feet, in a dewatered state.	A.2.1.28	Complete
53.	Reactor Head Closure Studs	Replace the spare reactor head closure stud(s) manufactured from the bar that has a yield strength > 150 ksi with ones that do not exceed 150 ksi.	A.2.1.3	Prior to the period of extended operation.

54.	Steam Generator Tube Integrity	NextEra will address the potential for cracking of the primary to secondary pressure boundary due to PWSCC of tube-to-tubesheet welds using one of the following two options: 1) Perform a one-time inspection of a representative sample of tube-to-tubesheet welds in all steam generators to determine if PWSCC cracking is present and, if cracking is identified, resolve the condition through engineering evaluation justifying continued operation or repair the condition, as appropriate, and establish an ongoing monitoring program to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators, or 2) Perform an analytical evaluation showing that the structural integrity of the steam generator tube-to-tubesheet interface is adequately maintaining the pressure boundary in the presence of tube-to-tubesheet weld cracking, or redefining the pressure boundary in which the tube-to-tubesheet weld is no longer included and, therefore, is not required for reactor coolant pressure boundary function. The redefinition of the reactor coolant pressure boundary must be approved by the NRC as part of a license amendment request.	A.2.1.10	Complete
55.	Steam Generator Tube Integrity	Seabrook will perform an inspection of each steam generator to assess the condition of the divider plate assembly.	A.2.1.10	Within five years prior to the period of extended operation.
56.	Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for hydrazine and sulfates.	A.2.1.12	Prior to the period of extended operation.
57.	Closed-Cycle Cooling Water System	Revise the station program documents to reflect the EPRI Guideline operating ranges and Action Level values for Diesel Generator Cooling Water Jacket pH.	A.2.1.12	Prior to the period of extended operation.

58.	Fuel Oil Chemistry	Update Technical Requirement Program 5.1, (Diesel Fuel Oil Testing Program) ASTM standards to ASTM D2709-96 and ASTM D4057-95 required by the GALL XI.M30 Rev 1	A.2.1.18	Prior to the period of extended operation.
59.	Nickel Alloy Nozzles and Penetrations	The Nickel Alloy Aging Nozzles and Penetrations program will implement applicable Bulletins, Generic Letters, and staff accepted industry guidelines.	A.2.2.3	Prior to the period of extended operation.
60.	Buried Piping and Tanks Inspection	Implement the design change replacing the buried Auxiliary Boiler supply piping with a pipe-within-pipe configuration with leak detection capability.	A.2.1.22	Prior to the period of extended operation.
61.	Compressed Air Monitoring Program	Replace the flexible hoses associated with the Diesel Generator air compressors on a frequency of every 10 years.	A.2.1.14	Within ten years prior to the period of extended operation.
62.	Water Chemistry	Enhance the program to include a statement that sampling frequencies are increased when chemistry action levels are exceeded.	A.2.1.2	Prior to the period of extended operation.
63.	Flow Induced Erosion	Ensure that the quarterly CVCS Charging Pump testing is continued during the PEO. Additionally, add a precaution to the test procedure to state that an increase in the CVCS Charging Pump mini flow above the acceptance criteria may be indicative of erosion of the mini flow orifice as described in LER 50-275/94-023.	A.2.1.2	Prior to the period of extended operation.
64.	Buried Piping and Tanks Inspection	Soil analysis shall be performed prior to entering the period of extended operation to determine the corrosivity of the soil in the vicinity of non-cathodically protected steel pipe within the scope of this program. If the initial analysis shows the soil to be non-corrosive, this analysis will be re-performed every ten years thereafter.	A.2.1.22	***Within ten years p***rior to the period of extended operation.
65.	Flux Thimble Tube	Implement measures to ensure that the movable incore detectors are not returned to service during the period of extended operation.	N/A	Prior to the period of extended operation. – In Progress

66.	Number Not Used			
67.	Structures Monitoring Program	Perform one shallow core bore in an area that was continuously wetted from borated water to be examined for concrete degradation and also expose rebar to detect any degradation such as loss of material. The removed core will also be subjected to petrographic examination for concrete degradation due to ASR per ASTM Standard Practice C856.	A.2.1.31	Complete
68.	Structures Monitoring Program	Perform sampling at the leak off collection points for chlorides, sulfates, pH and iron once every three months.	A.2.1.31	Complete
69.	Open-Cycle Cooling Water System	Replace the Diesel Generator Heat Exchanger Plastisol PVC lined Service Water piping with piping fabricated from AL6XN material.	A.2.1.11	Complete
70.	Closed-Cycle Cooling Water System	Inspect the piping downstream of CC-V-444 and CC-V-446 to determine whether the loss of material due to cavitation induced erosion has been eliminated or whether this remains an issue in the primary component cooling water system.	A.2.1.12	Within ten years prior to the period of extended operation.
71.	Alkali-Silica Reaction (ASR) Monitoring Program / Building Deformation Monitoring Program	NextEra has completed testing at the University of Texas Ferguson Structural Engineering Laboratory which demonstrates the parameters being monitored and acceptance criteria used are appropriate to manage the effects of ASR. NextEra Iimplement the Alkali-Silica Reaction (ASR) Monitoring Program and Building Deformation Monitoring Program described in B.2.1.31A and B.2.1.31B of the License Renewal Application.	A.2.1.31A A.2.1.31B	Prior to the period of extended operation.
72.	Flow-Accelerated Corrosion	Enhance the program to include management of wall thinning caused by mechanisms other than FAC.	A.2.1.8	Prior to the period of extended operation.

73.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Enhance the program to include performance of focused examinations to provide a representative sample of 20%, or a maximum of 25, of each identified material, environment, and aging effect combinations during each 10 year period in the period of extended operation.	A.2.1.25	Prior to the period of extended operation.
74.	Fire Water System	Enhance the program to perform sprinkler inspections annually per the guidance provided in NFPA 25 (2011 Edition). Inspection will ensure that sprinklers are free of corrosion, foreign materials, paint, and physical damage and installed in the proper orientation (e.g., upright, pendant, or sidewall). Any sprinkler that is painted, corroded, damaged, loaded, or in the improper orientation, and any glass bulb sprinkler where the bulb has emptied, will be evaluated for replacement.	A.2.1.16	Prior to the period of extended operation.
75.	Fire Water System	Enhance the program to a) conduct an inspection of piping and branch line conditions every 5 years by opening a flushing connection at the end of one main and by removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign organic and inorganic material per the guidance provided in NFPA 25 (2011 Edition) and b) If the presence of sufficient foreign organic or inorganic material to obstruct pipe or sprinklers is detected during pipe inspections, the material will be removed and its source is determined and corrected. In buildings having multiple wet pipe systems, every other system shall have an internal inspection of piping every 5 years as described in NFPA 25 (2011 Edition), Section 14.2.2.	A.2.1.16	Prior to the period of extended operation.

76.	Fire Water System	Enhance the Program to conduct the following activities annually per the guidance provided in NFPA 25 (2011 Edition). • main drain tests • deluge valve trip tests • fire water storage tank exterior surface inspections	A.2.1.16	Prior to the period of extended operation.
77.	Fire Water System	The Fire Water System Program will be enhanced to include the following requirements related to the main drain testing per the guidance provided in NFPA 25 (2011 Edition). • The requirement that if there is a 10 percent reduction in full flow pressure when compared to the original acceptance tests or previously performed tests, the cause of the reduction shall be identified and corrected if necessary. • Recording the time taken for the supply water pressure to return to the original static (nonflowing) pressure.	A.2.1.16	Prior to the period of extended operation.
78.	External Surfaces Monitoring	Enhance the program to include periodic inspections of in-scope insulated components for possible corrosion under insulation. A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), will be periodically inspected every 10 years during the period of extended operation.	A.2.1.24	Prior to the period of extended operation.
79.	Open-Cycle Cooling Water System	Enhance the program to include visual inspection of internal coatings/linings for loss of coating integrity.	A.2.1.11	Within 10 years prior to the period of extended operation.
80.	Fire Water System	Enhance the program to include visual inspection of internal coatings/linings for loss of coating integrity.	A.2.1.16	Within 10 years prior to the period of extended operation.

81.	Fuel Oil Chemistry	Enhance the program to include visual inspection of internal coatings/linings for loss of coating integrity.	A.2.1.18	Within 10 years prior to the period of extended operation.
82.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Enhance the program to include visual inspection of internal coatings/linings for loss of coating integrity.	A.2.1.25	Within 10 years prior to the period of extended operation.
83.	Alkali-Silica Reaction Monitoring	Enhance the ASR AMP to install extensometers in all Tier 3 areas of two dimensional reinforced structures to monitor expansion due to alkali-silica reaction in the out-of-plane direction. Monitoring expansion in the out-of-plane direction will commence upon installation of the extensometers and continue on a six month frequency through the period of extended operation.	A.2.1.31A	December 31,2016.
84.	ASME Section XI, Subsection IWL	Evaluate the acceptability of inaccessible areas for structures within the scope of ASME Section XI, Subsection IWL Program.	A.2.1.28	Prior to the period of extended operation.
85.	Fire Water System	Enhance the program to perform additional tests and inspections on the Fire Water Storage Tanks as specified in Section 9.2.7 of NFPA 25 (2011 Edition) in the event that it is required by Section 9.2.6.4, which states "Steel tanks exhibiting signs of interior pitting, corrosion, or failure of coating shall be tested in accordance with 9.2.7."	A.2.1.16	Prior to the period of extended operation.
86.	Fire Water System	Enhance the program to include disassembly, inspection, and cleaning of the mainline strainers every 5 years.	A.2.1.16	Prior to the period of extended operation.
87.	Fire Water System	Increase the frequency of the Open Head Spray Nozzle Air Flow Test from every 3 years to every refueling outage to be consistent with LR-ISG-2012-02, AMP XI.M27, Table 4a.	A.2.1.16	Prior to the period of extended operation.

88.	Fire Water System	Enhance the program to include verification that a) the drain holes associated with the transformer deluge system are draining to ensure complete drainage of the system after each test, b) the deluge system drains and associated piping are configured to completely drain the piping, and c) normally-dry piping that could have been wetted by inadvertent system actuations or those that occur after a fire are restored to a dry state as part of the suppression system restoration.	A.2.1.16	Within five years prior to the period of extended operation.
89.	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Incorporate Coating Service Level III requirements into the RCP Motor Refurbishment Specification for the internal painting of the motor upper bearing coolers and motor air coolers. All four RCP motors will be refurbished and replaced using the Coating Service Level III requirements prior to entering the period of extended operation.	A.2.1.25	Prior to the period of extended operation.
90.	PWR Vessel Internals	Implement the PWR Vessel Internals Program. The program will be implemented in accordance with MRP-227-A (Pressurized Water Reactor Internals Inspection and Evaluation Guidelines) and NEI 03-08 (Guideline for the Management of Materials Issues).	A.2.1.7	Prior to the period of extended operation

91	Building Deformation Monitoring	Implement the Building Deformation Monitoring Program Enhance Structures Monitoring Program to require structural evaluations be performed on buildings and components affected by deformation as necessary to ensure that the structural function is maintained. Evaluations of structures will validate structural performance against the design basis, and may use results from the large-scale test programs, as appropriate. Evaluations for structural deformation will also consider the impact to functionality of affected systems and components (e.g., conduit expansion joints). NextEra will evaluate the specific circumstances against the design basis of the affected system or component. Enhance the Building Deformation AMP to include additional parameters to be monitored based on the results of the CEB Root Cause, Structural Evaluation and walk downs. Additional parameters monitored will include: alignment of ducting, conduit, and piping; seal integrity; laser target measurements; key seismic gap measurements; and additional instrumentation.	A.2.1.31B	March 15, 2020