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NL-17-161

December 21, 2017

U.S. Nuclear Regulatory Commission
Document Control Desk
11545 Rockville Pike, TWFN-2 F1
Rockville, MD 20852-2738

SUBJECT: Supplemental Information Regarding the Service Water Integrity Aging Management Program for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (LRA) (CAC Nos. MD5407 and MD5408)
Docket Nos. 50-247 and 50-286
Licenses Nos. DPR-26 and DPR-64)

REFERENCES:

1) Entergy Letter, "Supplemental Information Regarding the Service Water Integrity Aging Management Program for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (LRA) (CAC Nos. MD5407 and MD5408)," dated November 8, 2017 (NL-17-127)
2) USNRC Letter, "Service Water Integrity Aging Management Program Audit Report for the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application (CAC Nos. MD5407 and MD5408)," dated September 20, 2017 (ML17250A244)
3) USNRC Letter, "Summary of Telephone Conference Call Held on September 6, 2017, Between the U.S. Nuclear Regulatory Commission and Entergy Nuclear Operations, Inc. Concerning Next Actions from the Site Audit Held from August 1-3, 2017, Pertaining to the Indian Point, License Renewal Application (TAC. NOS. MD5407/MD5408)," dated September 25, 2017 (ML17256A286)
4) Entergy Letter, "Reply to Request for Additional Information for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3, License Renewal Application, SET 2017-01(CAC Nos. MD5407 and MD5408)," dated May 8, 2017 (NL-17-052) (ML17132A175)
5) Entergy Letter, "Amendment to License Renewal Application – Reflecting Shortened License Renewal Terms for Units 2 and 3," dated February 8, 2017 (NL-17-019) (ML17044A005)
6) Entergy Letter, "Re-Submittal of Supplemental Information Regarding the Service Water Integrity Aging Management Program for the Review of the Indian Point Nuclear Generating Unit Nos. 2 and 3 License Renewal Application (LRA) (CAC Nos. MD5407 and MD5408)," dated December 14, 2017 (NL-17-155)

A178
NRR

Dear Sir or Madam:

From August 1 - 3, 2017, the U.S. Nuclear Regulatory Commission (NRC) staff conducted a supplemental, on-site regulatory audit to gain a better understanding of Entergy Nuclear Operations, Inc.'s (Entergy) response to the request for additional information (RAI), submitted by letter dated May 8, 2017 and new plant-specific operating experience related to the Service Water Integrity Aging Management Program. Following the completion of the audit, the NRC staff issued an audit report, which identified several areas where the aging management activities for the Service Water System warrant additional clarification or further information.

By letter dated November 8, 2017 (Reference 1), Entergy provided supplemental information regarding the Service Water Integrity Aging Management Program in response to the August 1 – 3, 2017 on-site regulatory audit. On November 30, 2017, a conference call was held between the NRC and Entergy to clarify Entergy's responses for Audit Items 3 and 6 as discussed in Reference 1. By letter dated December 14, 2017 (Reference 6), Entergy provided additional information to clarify specific areas in the Entergy response to the audit report. Reference 6 revised our previous responses to Audit Items 3 and 6, replacing Reference 1 in its entirety.

On December 19, 2017, Entergy personnel participated in a conference call with members of the NRC staff to discuss the need for additional clarification of the Entergy response to the report of the August 2017 service water audit. As a result of the conference call, Entergy is providing additional clarification to the response to audit items 2 and 3. The additional information is shown in Attachment 1 as revisions to the affected portions of Reference 6. Changes to the LRA sections resulting from the information provided in Attachment 1 are provided in Attachment 2. Changes to the List of Regulatory Commitments are provided in Attachment 3.

If you have any questions, or require additional information, please contact Mr. Robert Walpole at 914-254-6710.

I declare under penalty of perjury that the foregoing is true and correct. Executed on 12-21-17, 2017.

Sincerely,

AJV/mm

Attachments:
1. Supplemental Information Regarding the License Renewal Application Service Water Integrity Program
2. License Renewal Application Changes As a Result of Supplemental Information
3. License Renewal Application IPEC List of Regulatory Commitments Revision 37

cc: Mr. David C. Lew, Acting Regional Administrator, NRC Region I
Mr. William Burton, Senior Project Manager, NRC DLR
Mr. Richard V. Guzman, Senior Project Manager, NRC NRR DORL
Ms. Bridget Frymire, New York State Department of Public Service
Ms. Alicia Barton, President and CEO NYSERDA
NRC Resident Inspector's Office

ATTACHMENT 1

to NL-17-161

SUPPLEMENTAL INFORMATION

REGARDING THE

LICENSE RENEWAL APPLICATION

SERVICE WATER INTEGRITY PROGRAM

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

NRC AUDIT REPORT ITEM 2

Installation of External Carbon Fiber Repair on Service Water Pipe Weld PAB-204. The staff reviewed engineering change (EC) 61654 and noted that the repair of the non-safety-related pipe was "designed to act as the original piping should the weld fail and structural integrity compromised." The EC specified that the installation include: (a) seven layers of wrap, (b) a 6 inch overlap, and (c) a minimum total wrap length of 6 feet upstream and downstream of the weld. The staff reviewed WO 00404774-01 and noted that, except for the specified overlap at the elbow, all installation parameters were met. For the overlap at the elbow, the staff reviewed ECN 72788 for allowing the field to fit up the carbon fiber wrap with additional layers to compensate for the inability to uniformly obtain a 6 inch overlap.

Because the credited piping material changed from carbon steel to a nonmetallic composite, Entergy may need to address different aging effects with different inspection requirements. In addition Entergy may need alternate inspection techniques, because the inability to detect leakage through the composite material may not allow the detection of ongoing internal corrosion at locations where structural integrity is needed at the carbon steel-to-nonmetallic composite interface. To address the issues introduced by this repair, the staff needs additional information regarding: a) the aging effects that need to be managed for the nonmetallic composite material (with associated aging management program, if applicable) and b) confirmation that degradation of cement-lined service water piping has not occurred at locations other than at welds (e.g. mid-span between welds) such that alternate inspection requirements would be needed to confirm the structural integrity near the carbon steel to nonmetallic composite interface locations.

RESPONSE:

A section of IP3 24-inch diameter service water return piping, including an elbow, was overlaid with carbon fiber-reinforced epoxy at elevation 41 feet in the primary auxiliary building due to corrosion adjacent to the downstream elbow to pipe weld. The carbon fiber-reinforced epoxy overlay provides strength and design characteristics equivalent to the original piping. The piping was prepared prior to application to ensure that the carbon fiber-reinforced epoxy material properly adheres to the pipe.

Aging effects that could occur for the carbon fiber-reinforced epoxy were evaluated.

The carbon fiber-reinforced epoxy material is a bidirectional carbon fiber fabric saturated with epoxy resin. Because the internal surface of the carbon fiber-reinforced epoxy coating is tightly adhered to the carbon steel surface of the piping, no aging effects requiring management could occur without a through-wall leak in the underlying carbon steel piping. The minimum wall thickness of the piping was 0.121 inches in January, 2015, after approximately 40 years of operation. This corresponds to a corrosion rate of approximately 0.006 inches per year. At IP3, the assumed service water piping corrosion rate is 0.012 inches per year. Using a corrosion rate of just less than 0.012 inches per year instead of the calculated corrosion rate, localized corrosion would not be through-wall by April 30, 2025. As discussed in Reference 5, Entergy has filed an amendment to the IPEC License Renewal Application (LRA) changing the end date of the proposed term of the renewed license for IP3 to April 30, 2025. Based on this, the internal surface of the carbon fiber-reinforced epoxy is not expected to be in contact with raw water prior

to the end of the renewed license term. Entergy will perform a volumetric examination at the location identified with the minimum wall thickness in 2016 to confirm that the carbon steel piping is not degrading at a rate that will result in exposure of the internal surface of the carbon fiber-reinforced epoxy to raw water prior to the end of the renewed license term. The volumetric examination will be performed prior to 12/31/21. Therefore, a line item with an internal environment for the carbon fiber-reinforced epoxy is not necessary in revised LRA Table 3.3.2-2-IP3.

The external surface of the carbon fiber-reinforced epoxy is exposed to a cool indoor air environment with low light exposure, conditions that minimize the potential for aging effects due to temperature or ultraviolet light. In addition, the raw discharge water (service water) flowing through the piping is heated from the numerous loads that it cools, thereby reducing the potential for condensation. Although aging effects would be minimized due to these operating conditions, operating experience relative to long-term aging effects of carbon fiber-reinforced epoxy installations at nuclear plants is limited. As a result, aging effects will conservatively be identified for the carbon fiber-reinforced epoxy. Since the carbon fiber-reinforced epoxy entails fibrous material similar to fiberglass and both utilize epoxy, aging effects applicable to fiberglass are deemed potential aging effects. Cracking, blistering, and loss of material are conservatively identified as aging effects for the carbon fiber-reinforced epoxy external surface. Visual inspection performed in accordance with the Periodic Surveillance and Preventive Maintenance Program will manage these aging effects.

Entergy reviewed relevant OE of the service water system for the period of 2004-2016 and did not find relevant examples of leakage of the concrete lined piping at locations "mid-span" of the carbon steel welds. Therefore, no alternate inspection requirements are needed to confirm structural integrity near the carbon steel to nonmetallic composite interface locations.

The LRA is revised as shown in Attachment 2 with additions underlined and deletions lined through.

NRC AUDIT REPORT ITEM 3

Use of 6 Percent Molybdenum Stainless Steel (AL-6XN).

LER 247/2013-004 addresses pitting corrosion of 300 series stainless steel service water piping that was replaced with 6 percent molybdenum stainless steel (AL-6XN). Based on industry operating experience, the staff noted that, because AL-6XN has a more positive corrosion potential than 300 series stainless steels, the introduction of AL-6XN can increase the susceptibility of carbon steel to galvanic corrosion. During a breakout session, the applicant noted that the service water system contains dissimilar-metal flanged joints between carbon steel and AL-6XN, as well as 300 series stainless steel. Consequently, the staff questioned whether AL-6XN flanged components should be considered as a unique population within the Service Water Integrity program. During discussions, the plant staff stated that AL-6XN is sufficiently similar to 300 series stainless steels that components made from AL-6XN do not need to be considered as unique populations; however, the plant staff noted that the similarity is based on whether the surfaces of the stainless steel components have been passivated and the grade of 300 series stainless steel.

During its subsequent review of the Service Water Piping Specification (9321-01-248 35), the staff noted that the applicant had previously removed the requirement for the use of insulating kits on dissimilar-metal flanged joints. Because the absence of insulating kits increases the susceptibility of carbon steel to loss of material due to galvanic corrosion, it was not clear to the staff that the condition or absence of insulating kits on dissimilar-metal flanged joints could be disregarded. In order address the issues introduced by these changes, the staff needs additional information to determine whether current inspection of dissimilar-metal flanged connections can be credited by the Service Water Integrity program and whether AL-6XN needs to be considered as a unique population for these activities. The information needed by the staff includes: a) the difference in the corrosion potential of the stainless steel alloy(s) used in the service water system and the corrosion potential of AL-6XN, b) the environment in the vicinity of the 300 series stainless steel/carbon steel and AL-6XN/carbon steel joints, c) the coatings in the vicinity of the 300 series stainless steel/carbon steel and AL-6XN/carbon steel joints, and d) whether current inspections account for greater susceptibility to galvanic corrosion when insulating kits are not used.

RESPONSE:

An overall response is provided below, after the NRC's specific questions a) through d) are addressed.

Item a) the difference in the corrosion potential of the stainless steel alloy(s) used in the service water system and the corrosion potential of AL-6XN.

Response a):

AL-6XN tested in seawater has a 0 volts assignment.[1] The 300-series stainless steels voltage is approximately 0.0 to -0.13 volts.[2]

[1] AL-6XN ATI Technical brochure

Item b) the environments in the vicinity of the 300 series stainless steel/carbon steel and AL-6XN/carbon steel joints.

Response b):

As delineated in the LRA, the Service Water System has the following environments:

- Raw water (internal and external)
- Condensation (external)
- Treated water (internal and external)
- Air - indoor (internal and external)
- Air - outdoor (external)
- Soil (external)

The majority of the joints between carbon steel and AL-6XN or between carbon steel and stainless steel have an internal environment of raw water and an external environment of air or condensation.

Item c) the coatings in the vicinity of the 300 series stainless steel/carbon steel and AL-6XN/carbon steel joints.

Response c):

Generally, carbon steel piping 2" or greater in diameter is internally coated with cement. Cement lining repairs are made using internal coatings such as Waterplug, Enecon, or Belzona. The 300-series stainless steel grades, AL-6XN, and Avesta 254 SMO are not internally coated.[3] The faces of some 300-series stainless steel and carbon steel flanges may be coated, in whole or in part, with Enecon and/or Belzona products for corrosion repair and/or prevention purposes.

Item d) Whether current inspections account for greater susceptibility to galvanic corrosion when insulating kits are not used.

Response d):

Past Service Water Integrity Program inspections have not accounted for greater susceptibility to galvanic corrosion when insulating kits are not installed. The program focuses on the inspection of piping and pipe welds, which include dissimilar metal flange carbon steel butt welds.

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[2] DBI Galvanic Table

[3] IP3 Specification, "Specification For Service Water Piping and Piping Components," TS-MS-027, Revision 5, dated April 25, 2017 and IP2 Specification, "Specification For Service Water Piping," 9321-01-248, Revision 8, dated December 2, 2013

Overall Conclusion:

Entergy staff previously determined that insulating kits were not necessary and subsequently revised design specifications for IP2 and IP3 to remove the requirement for insulating kits. Therefore, the Service Water System contains dissimilar metal flanged joints both with and without insulating kits.

In addition to 6 percent molybdenum AL-6XN, another alloy, Avesta 254 SMO is used at IPEC. Although AL-6XN and Avesta 254 SMO have slightly different chemical compositions, they are considered equivalent materials. As an example, AL-6XN contains approximately 6 to 7 percent molybdenum, while Avesta 254 SMO contains 6 to 6.5 percent molybdenum.

The galvanic potential of AL-6XN is similar to the galvanic potential of 300-series stainless steels. Avesta 254 SMO has a material composition similar to AL-6XN and is expected to have a similar galvanic potential. Because of the similar galvanic potentials, galvanic corrosion rates are also expected to be similar when these materials are in contact with carbon steel. Therefore, Entergy will perform inspections for indications of galvanic corrosion from a combined population of joints where carbon steel is connected to AL-6XN or Avesta 254 SMO or 300-series stainless steel.

In order to ensure that loss of material due to galvanic corrosion is not affecting the ability of the Service Water System to perform its intended function, the following enhancement will be implemented.

Revise the Service Water Integrity Program procedures to perform internal and external visual inspections where feasible of flanged connections (including flange faces, bolting, and welds) where carbon steel is in contact with AL-6XN, Avesta 254 SMO, or 300-series stainless steel. The inspection population will be limited to dissimilar metal joints without galvanic insulating kits. Inspections will focus on the bounding or lead components most susceptible to galvanic corrosion based on time in service and severity of operating conditions. Inspections will monitor for evidence of loss of material due to galvanic corrosion on a representative sample consisting of 20 percent of the population up to a maximum of 25 inspections during each 10-year period of the period of extended operation. Visual inspection results that identify appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program and a follow-up volumetric wall thickness examination ~~If significant loss of material is identified by the visual inspections, additional volumetric NDE~~ will be performed to characterize the extent of the degradation.

The LRA is revised as shown in Attachment 2 with additions underlined and deletions lined through.

ATTACHMENT 2

to NL-17-161

LICENSE RENEWAL APPLICATION CHANGES

AS A RESULT OF

SUPPLEMENTAL INFORMATION

Deletions are shown with strike-through and additions are underlined.

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

A.2.1.33Service Water Integrity Program

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water and monitoring of the silt levels in the intake bays. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Scheduling of nonsafety-related piping examinations is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

The Service Water Integrity Program will be enhanced to include the following.

...

- Revise Service Water Integrity Program procedures to perform internal visual inspections of flanged connections where carbon steel is in contact with AL-6XN, Avesta 254 SMO, or 300-series stainless steel. The inspection population will be dissimilar metal joints without galvanic insulating kits. Inspections will focus on the bounding or lead components most susceptible to galvanic corrosion based on time in service and severity of operating conditions. Inspections will monitor for evidence of loss of material due to galvanic corrosion on a representative sample consisting of 20 percent of the population, up to a maximum of 25 inspections, during each 10-year period of the period of extended operation. Visual inspection results that identify appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program and a follow-up volumetric wall thickness examination ~~If significant loss of material is identified by the visual inspections, additional volumetric NDE~~ will be performed to characterize the extent of the degradation.

A.3.1.33 Service Water Integrity Program

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water and monitoring of the silt levels in the intake bays. Chemical treatment using biocides and chlorine and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Scheduling of nonsafety-related piping examinations is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based

on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

The Service Water Integrity Program will be enhanced to include the following.

...

- Revise Service Water Integrity Program procedures to perform internal visual inspections of flanged connections where carbon steel is in contact with AL-6XN, Avesta 254 SMO, or 300-series stainless steel. The inspection population will be dissimilar metal joints without galvanic insulating kits. Inspections will focus on the bounding or lead components most susceptible to galvanic corrosion based on time in service and severity of operating conditions. Inspections will monitor for evidence of loss of material due to galvanic corrosion on a representative sample consisting of 20 percent of the population up to a maximum of 25 inspections during each 10-year period of the period of extended operation. Visual inspection results that identify appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program and a follow-up volumetric wall thickness examination ~~If significant loss of material is identified by the visual inspections, additional volumetric NDE~~ will be performed to characterize the extent of the degradation.

B.1.29 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE

Program Description

The Periodic Surveillance and Preventive Maintenance Program is an existing program that includes periodic inspections and tests that manage aging effects not managed by other aging management programs. In addition to specific activities in the plant's preventive maintenance program and surveillance program, the Periodic Surveillance and Preventive Maintenance Program includes enhancements to add new activities. The preventive maintenance and surveillance testing activities are generally implemented through repetitive tasks or routine monitoring of plant operations. Credit for program activities has been taken in the aging management review of the following systems and structures. All activities are new unless otherwise noted.

Service water system	Visually inspect the surface of the carbon fiber-reinforced epoxy overlay on line 405 in the Unit 3 primary auxiliary building to manage cracking, blistering, and loss of material. The inspection will be performed each operating cycle. Revise program documents to specify a one-time volumetric examination on line 405 at the location identified with the minimum wall thickness in 2016 to confirm that the carbon

steel piping is not degrading at a rate that will result in exposure of the internal surface of the carbon fiber-reinforced epoxy to raw water prior to the end of the renewed license term. The volumetric examination will be performed prior to December 31, 2021.

The following enhancements will be implemented prior to December 31, 2018.

Attributes Affected	Enhancements
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	Program activity guidance documents will be developed or revised as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

B.1.34 Service Water Integrity

Program Description

The Service Water Integrity Program is an existing program that relies on implementation of the recommendations of GL 89-13 to ensure that the effects of aging on the service water system are managed through the period of extended operation. The program includes component inspections for erosion, corrosion, and biofouling to verify the heat transfer capability of safety-related heat exchangers cooled by service water and monitoring of the silt levels in the intake bays. Chemical treatment using biocides and sodium hypochlorite and periodic cleaning and flushing of infrequently used loops are methods used to control fouling within the heat exchangers and to manage loss of material in service water components. Prioritization of internal examinations of SW piping is based on safety classification. Scheduling of nonsafety-related piping examination is determined by trending of examination results. Selection of large bore service water pipe points for volumetric inspection is based on piping configuration, results from previous inspections, consideration of follow-ups to previous repairs, and condition assessments when components are opened during preventive maintenance activities. Scope expansion for indications found by program inspections of nonsafety-related piping is based on engineering analysis, judgment and program experience. The factors that are considered include piping location, severity of use, piping materials, previous inspection results, and repair history.

NUREG-1801 Consistency

The Service Water Integrity Program is consistent with the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to December 31, 2018.

Attributes Affected	Enhancements
4. Detection of Aging Effects	• Revise the Service Water Integrity Program procedures to perform internal visual inspections of flanged connections where carbon steel is in contact with AL-6XN, Avesta 254 SMO, or 300-series stainless steel. The inspection population will be dissimilar metal joints without galvanic insulating kits. Inspections will focus on the bounding or lead components most susceptible to galvanic corrosion based on time in service and severity of operating conditions. Inspections will monitor for evidence of loss of material due to galvanic corrosion on a representative sample consisting of 20 percent of the population, up to a maximum of 25 inspections, during each 10-year period of the period of extended operation. Visual inspection results that identify appreciable localized corrosion (e.g., pitting) beyond a normal oxide layer will be entered into the corrective action program and a follow-up volumetric wall thickness examination ~~If significant loss of material is identified by the visual inspections, additional volumetric NDE~~ will be performed to characterize the extent of the degradation.

ATTACHMENT 3

to NL-17-161

LICENSE RENEWAL APPLICATION

IPEC LIST OF REGULATORY COMMITMENTS

Rev. 37

ENTERGY NUCLEAR OPERATIONS, INC.
INDIAN POINT NUCLEAR GENERATING UNIT NOS. 2 & 3
DOCKET NOS. 50-247 AND 50-286

List of Regulatory Commitments

Rev. 37

The following table identifies those actions committed to by Entergy in this document. Changes are shown as strike-through for ~~deletions~~ and underlines for additions.

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
1	Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to perform thickness measurements of the bottom surfaces of the condensate storage tanks, city water tank, and fire water tanks once during the first ten years of the period of extended operation. Enhance the Aboveground Steel Tanks Program for IP2 and IP3 to require trending of thickness measurements when material loss is detected.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1, A.3.1.1 and B.1.1, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.1 A.3.1.1 B.1.1
	Implement LRA Sections, A.2.1.1 and B.1.1, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.1 B.1.1
2	Enhance the Bolting Integrity Program for IP2 and IP3 to clarify that actual yield strength is used in selecting materials for low susceptibility to SCC and clarify the prohibition on use of lubricants containing MoS_2 for bolting. The Bolting Integrity Program manages loss of preload and loss of material for all external bolting.	IP2: Complete IP3: Complete	NL-07-039 NL-07-153 NL-13-122	A.2.1.2 A.3.1.2 B.1.2 Audit Items 201, 241, 270

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
3	Implement the Buried Piping and Tanks Inspection Program for IP2 and IP3 as described in LRA Section B.1.6. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M34, Buried Piping and Tanks Inspection. Include in the Buried Piping and Tanks Inspection Program described in LRA Section B.1.6 a risk assessment of in-scope buried piping and tanks that includes consideration of the impacts of buried piping or tank leakage and of conditions affecting the risk for corrosion. Classify pipe segments and tanks as having a high, medium or low impact of leakage based on the safety class, the hazard posed by fluid contained in the piping and the impact of leakage on reliable plant operation. Determine corrosion risk through consideration of piping or tank material, soil resistivity, drainage, the presence of cathodic protection and the type of coating. Establish inspection priority and frequency for periodic inspections of the in-scope piping and tanks based on the results of the risk assessment. Perform inspections using inspection techniques with demonstrated effectiveness.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-09-106 NL-09-111 NL-11-101	A.2.1.5 A.3.1.5 B.1.6 Audit Item 173
4	Enhance the Diesel Fuel Monitoring Program to include cleaning and inspection of the IP2 GT-1 gas turbine fuel oil storage tanks, IP2 and IP3 EDG fuel oil day tanks, IP2 SBO/Appendix R diesel generator fuel oil day tank, and IP3 Appendix R fuel oil storage tank and day tank once every ten years. Enhance the Diesel Fuel Monitoring Program to include quarterly sampling and analysis of the IP2 SBO/Appendix R diesel generator fuel oil day tank, IP2 security diesel fuel oil storage tank, IP2 security diesel fuel oil day tank, and IP3 Appendix R fuel oil storage tank. Particulates, water and sediment checks will be performed on the samples. Filterable solids acceptance criterion will be less than or equal to 10mg/l. Water and sediment acceptance criterion will be less than or equal to 0.05%.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057	A.2.1.8 A.3.1.8 B.1.9 Audit items 128, 129, 132, 491, 492, 510

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Enhance the Diesel Fuel Monitoring Program to include thickness measurement of the bottom of the following tanks once every ten years. IP2: EDG fuel oil storage tanks, EDG fuel oil day tanks, SBO/Appendix R diesel generator fuel oil day tank, GT-1 gas turbine fuel oil storage tanks, and diesel fire pump fuel oil storage tank; IP3: EDG fuel oil day tanks, EDG fuel oil storage tanks, Appendix R fuel oil storage tank, and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to change the analysis for water and particulates to a quarterly frequency for the following tanks. IP2: GT-1 gas turbine fuel oil storage tanks and diesel fire pump fuel oil storage tank; IP3: Appendix R fuel oil day tank and diesel fire pump fuel oil storage tank. Enhance the Diesel Fuel Monitoring Program to specify acceptance criteria for thickness measurements of the fuel oil storage tanks within the scope of the program. Enhance the Diesel Fuel Monitoring Program to direct samples be taken and include direction to remove water when detected. Revise applicable procedures to direct sampling of the onsite portable fuel oil contents prior to transferring the contents to the storage tanks. Enhance the Diesel Fuel Monitoring Program to direct the addition of chemicals including biocide when the presence of biological activity is confirmed.			
5	Enhance the External Surfaces Monitoring Program for IP2 and IP3 to include periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3). Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).	IP2: Complete	NL-07-039 NL-13-122	A.2.1.10 A.3.1.10 B.1.11

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.10, A.3.1.10 and B.1.11, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.10 A.3.1.10 B.1.11
6	Enhance the Fatigue Monitoring Program for IP2 to monitor steady state cycles and feedwater cycles or perform an evaluation to determine monitoring is not required. Review the number of allowed events and resolve discrepancies between reference documents and monitoring procedures. Enhance the Fatigue Monitoring Program for IP3 to include all the transients identified. Assure all fatigue analysis transients are included with the lowest limiting numbers. Update the number of design transients accumulated to date.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.11 A.3.1.11 B.1.12, Audit Item 164
7	Enhance the Fire Protection Program to inspect external surfaces of the IP3 RCP oil collection systems for loss of material each refueling cycle. Enhance the Fire Protection Program to explicitly state that the IP2 and IP3 diesel fire pump engine sub-systems (including the fuel supply line) shall be observed while the pump is running. Acceptance criteria will be revised to verify that the diesel engine does not exhibit signs of degradation while running; such as fuel oil, lube oil, coolant, or exhaust gas leakage. Enhance the Fire Protection Program to specify that the IP2 and IP3 diesel fire pump engine carbon steel exhaust components are inspected for evidence of corrosion and cracking at least once each operating cycle. Enhance the Fire Protection Program for IP3 to visually inspect the cable spreading room, 480V switchgear room, and EDG room CO_2 fire suppression system for signs of degradation, such as corrosion and mechanical damage at least once every six months.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.12 A.3.1.12 B.1.13

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
8	Enhance the Fire Water Program to include inspection of IP2 and IP3 hose reels for evidence of corrosion. Acceptance criteria will be revised to verify no unacceptable signs of degradation. Enhance the Fire Water Program to replace all or test a sample of IP2 and IP3 sprinkler heads required for 10 CFR 50.48 using guidance of NFPA 25 (2002 edition), Section 5.3.1.1.1 before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation to ensure that signs of degradation, such as corrosion, are detected in a timely manner. Enhance the Fire Water Program to perform wall thickness evaluations of IP2 and IP3 fire protection piping on system components using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material due to corrosion. These inspections will be performed before the end of the current operating term and at intervals thereafter during the period of extended operation. Results of the initial evaluations will be used to determine the appropriate inspection interval to ensure aging effects are identified prior to loss of intended function. Enhance the Fire Water Program to inspect the internal surface of foam based fire suppression tanks. Acceptance criteria will be enhanced to verify no significant corrosion.	IP2: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-014	A.2.1.13 A.3.1.13 B.1.14 Audit Items 105, 106
	Implement LRA Sections, A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-14-147.	IP2 & IP3: December 31, 2019	NL-14-147	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-15-019	IP2 & IP3: December 31, 2019	NL-15-019	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-15-092	IP2 & IP3: December 31, 2019	NL-15-092	A.2.1.13 A.3.1.13 B.1.14

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.13, A.3.1.13 and B.1.14, as shown in NL-16-122[4]	IP2 & IP3: December 31, 2017	NL-16-122	A.2.1.13 A.3.1.13 B.1.14
	Implement LRA Sections A.2.1.13, A.3.1.13, and B.1.14, as shown in NL-17-052	IP2 & IP3: December 31, 2017	NL-17-052	A.2.1.13 A.3.1.13 B.1.14
9	Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to implement comparisons to wear rates identified in WCAP-12866. Include provisions to compare data to the previous performances and perform evaluations regarding change to test frequency and scope. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to specify the acceptance criteria as outlined in WCAP-12866 or other plant-specific values based on evaluation of previous test results. Enhance the Flux Thimble Tube Inspection Program for IP2 and IP3 to direct evaluation and performance of corrective actions based on tubes that exceed or are projected to exceed the acceptance criteria. Also stipulate that flux thimble tubes that cannot be inspected over the tube length and cannot be shown by analysis to be satisfactory for continued service, must be removed from service to ensure the integrity of the reactor coolant system pressure boundary.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.15 A.3.1.15 B.1.16

[4] This commitment erroneously deleted in NL-17-052

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
10	Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include the following heat exchangers in the scope of the program. • Safety injection pump lube oil heat exchangers • RHR heat exchangers • RHR pump seal coolers • Non-regenerative heat exchangers • Charging pump seal water heat exchangers • Charging pump fluid drive coolers • Charging pump crankcase oil coolers • Spent fuel pit heat exchangers • Secondary system steam generator sample coolers • Waste gas compressor heat exchangers • SBO/Appendix R diesel jacket water heat exchanger (IP2 only) Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to perform visual inspection on heat exchangers where non-destructive examination, such as eddy current inspection, is not possible due to heat exchanger design limitations. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to include consideration of material-environment combinations when determining sample population of heat exchangers. Enhance the Heat Exchanger Monitoring Program for IP2 and IP3 to establish minimum tube wall thickness for the new heat exchangers identified in the scope of the program. Establish acceptance criteria for heat exchangers visually inspected to include no indication of tube erosion, vibration wear, corrosion, pitting, fouling, or scaling.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-09-018	A.2.1.16 A.3.1.16 B.1.17, Audit Item 52
11	Deleted		NL-09-056 NL-11-101	
12	Enhance the Masonry Wall Program for IP2 and IP3 to specify that the IP1 intake structure is included in the program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.18 A.3.1.18 B.1.19

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
13	Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to visually inspect the external surface of MEB enclosure assemblies for loss of material at least once every 10 years. The first inspection will occur prior to the period of extended operation and the acceptance criterion will be no significant loss of material. Enhance the Metal-Enclosed Bus Inspection Program to add acceptance criteria for MEB internal visual inspections to include the absence of indications of dust accumulation on the bus bar, on the insulators, and in the duct, in addition to the absence of indications of moisture intrusion into the duct. Enhance the Metal-Enclosed Bus Inspection Program for IP2 and IP3 to inspect bolted connections at least once every five years if performed visually or at least once every ten years using quantitative measurements such as thermography or contact resistance measurements. The first inspection will occur prior to the period of extended operation. The plant will process a change to applicable site procedure to remove the reference to "re-torquing" connections for phase bus maintenance and bolted connection maintenance.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057 NL-13-077	A.2.1.19 A.3.1.19 B.1.20 Audit Items 124, 133, 519
14	Implement the Non-EQ Bolted Cable Connections Program for IP2 and IP3 as described in LRA Section B.1.22.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.21 A.3.1.21 B.1.22
15	Implement the Non-EQ Inaccessible Medium-Voltage Cable Program for IP2 and IP3 as described in LRA Section B.1.23. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E3, Inaccessible Medium-Voltage Cables Not Subject To 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-11-032 NL-11-096 NL-11-101	A.2.1.22 A.3.1.22 B.1.23 Audit item 173

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
16	Implement the Non-EQ Instrumentation Circuits Test Review Program for IP2 and IP3 as described in LRA Section B.1.24. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E2, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.23 A.3.1.23 B.1.24 Audit item 173
17	Implement the Non-EQ Insulated Cables and Connections Program for IP2 and IP3 as described in LRA Section B.1.25. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.E1, Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.24 A.3.1.24 B.1.25 Audit item 173
18	Enhance the Oil Analysis Program for IP2 to sample and analyze lubricating oil used in the SBO/Appendix R diesel generator consistent with the oil analysis for other site diesel generators. Enhance the Oil Analysis Program for IP2 and IP3 to sample and analyze generator seal oil and turbine hydraulic control oil. Enhance the Oil Analysis Program for IP2 and IP3 to formalize preliminary oil screening for water and particulates and laboratory analyses including defined acceptance criteria for all components included in the scope of this program. The program will specify corrective actions in the event acceptance criteria are not met. Enhance the Oil Analysis Program for IP2 and IP3 to formalize trending of preliminary oil screening results as well as data provided from independent laboratories.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-101 NL-15-121	A.2.1.25 A.3.1.25 B.1.26

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
19	Implement the One-Time Inspection Program for IP2 and IP3 as described in LRA Section B.1.27. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M32, One-Time Inspection.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.26 A.3.1.26 B.1.27 Audit item 173
20	Implement the One-Time Inspection – Small Bore Piping Program for IP2 and IP3 as described in LRA Section B.1.28. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M35, One-Time Inspection of ASME Code Class I Small-Bore Piping.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.27 A.3.1.27 B.1.28 Audit item 173
21	Enhance the Periodic Surveillance and Preventive Maintenance Program for IP2 and IP3 as necessary to assure that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Sections A.2.1.28, A.3.1.28 and B.1.29, as shown in NL-16-122[5]	IP2 & IP3: December 31, 2017	NL-16-122	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Sections A.2.1.28, A.3.1.28 and B.1.29, as shown in NL-17-052	IP2 & IP3: December 31, 2017	NL-17-052	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Sections A.2.1.28, A.3.1.28 and B.1.29, as shown in NL-17-155	IP2 & IP3: December 31, 2018	NL-17-155	A.2.1.28 A.3.1.28 B.1.29
	Implement LRA Section B.1.29 as shown in NL-17-161	IP2 & IP3: December 31, 2018	NL-17-161	B.1.29

[5] This commitment erroneously deleted in NL-17-052

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
22	Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 revising the specimen capsule withdrawal schedules to draw and test a standby capsule to cover the peak reactor vessel fluence expected through the end of the period of extended operation. Enhance the Reactor Vessel Surveillance Program for IP2 and IP3 to require that tested and untested specimens from all capsules pulled from the reactor vessel are maintained in storage.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.1.31 A.3.1.31 B.1.32
23	Implement the Selective Leaching Program for IP2 and IP3 as described in LRA Section B.1.33. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M33 Selective Leaching of Materials.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.32 A.3.1.32 B.1.33 Audit item 173
24	Enhance the Steam Generator Integrity Program for IP2 and IP3 to require that the results of the condition monitoring assessment are compared to the operational assessment performed for the prior operating cycle with differences evaluated.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122	A.2.1.34 A.3.1.34 B.1.35
25	Enhance the Structures Monitoring Program to explicitly specify that the following structures are included in the program. • Appendix R diesel generator foundation (IP3) • Appendix R diesel generator fuel oil tank vault (IP3) • Appendix R diesel generator switchgear and enclosure (IP3) • city water storage tank foundation • condensate storage tanks foundation (IP3) • containment access facility and annex (IP3) • discharge canal (IP2/3) • emergency lighting poles and foundations (IP2/3) • fire pumphouse (IP2) • fire protection pumphouse (IP3) • fire water storage tank foundations (IP2/3) • gas turbine 1 fuel storage tank foundation • maintenance and outage building-elevated passageway (IP2)	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121 NL-08-057 NL-13-077	A.2.1.35 A.3.1.35 B.1.36 Audit items 86, 87, 88, 417

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	• new station security building (IP2) • nuclear service building (IP1) • primary water storage tank foundation (IP3) • refueling water storage tank foundation (IP3) • security access and office building (IP3) • service water pipe chase (IP2/3) • service water valve pit (IP3) • transformer/switchyard support structures (IP2) • waste holdup tank pits (IP2/3) Enhance the Structures Monitoring Program for IP2 and IP3 to clarify that in addition to structural steel and concrete, the following commodities (including their anchorages) are inspected for each structure as applicable. • cable trays and supports • concrete portion of reactor vessel supports • conduits and supports • cranes, rails and girders • equipment pads and foundations • fire proofing (pyrocrete) • HVAC duct supports • jib cranes • manholes and duct banks • manways, hatches and hatch covers • monorails • new fuel storage racks • sumps Enhance the Structures Monitoring Program for IP2 and IP3 to inspect inaccessible concrete areas that are exposed by excavation for any reason. IP2 and IP3 will also inspect inaccessible concrete areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant concrete degradation is occurring. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspections of elastomers (seals, gaskets, seismic joint filler, and roof elastomers) to		NL-14-146 NL-13-077	

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	identify cracking and change in material properties and for inspection of aluminum vents and louvers to identify loss of material. Enhance the Structures Monitoring Program for IP2 and IP3 to perform an engineering evaluation of groundwater samples to assess aggressiveness of groundwater to concrete on a periodic basis (at least once every five years). IPEC will obtain samples from at least 5 wells that are representative of the ground water surrounding below-grade site structures and perform an engineering evaluation of the results from those samples for sulfates, pH and chlorides. Additionally, to assess potential indications of spent fuel pool leakage, IPEC will sample for tritium in groundwater wells in close proximity to the IP2 spent fuel pool at least once every 3 months. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of normally submerged concrete portions of the intake structures at least once every 5 years. Inspect the baffling/grating partition and support platform of the IP3 intake structure at least once every 5 years. Enhance the Structures Monitoring Program for IP2 and IP3 to perform inspection of the degraded areas of the water control structure once per 3 years rather than the normal frequency of once per 5 years during the PEO. Enhance the Structures Monitoring Program to include more detailed quantitative acceptance criteria for inspections of concrete structures in accordance with ACI 349.3R, "Evaluation of Existing Nuclear Safety-Related Concrete Structures" prior to the period of extended operation.		NL-08-127 NL-11-032 NL-11-101	Audit Item 360 Audit Item 358

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
26	Implement the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.37. This new program will be implemented consistent with the corresponding program described in NUREG-1801, Section XI.M12, Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-15-121	A.2.1.36 A.3.1.36 B.1.37 Audit item 173
27	Implement the Thermal Aging and Neutron Irradiation Embrittlement of Cast Austenitic Stainless Steel (CASS) Program for IP2 and IP3 as described in LRA Section B.1.38. This new program will be implemented consistent with the corresponding program described in NUREG-1801 Section XI.M13, Thermal Aging and Neutron Embrittlement of Cast Austenitic Stainless Steel (CASS) Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153	A.2.1.37 A.3.1.37 B.1.38 Audit item 173
28	Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain water chemistry of the IP2 SBO/Appendix R diesel generator cooling system per EPRI guidelines. Enhance the Water Chemistry Control – Closed Cooling Water Program to maintain the IP2 and IP3 security generator and fire protection diesel cooling water pH and glycol within limits specified by EPRI guidelines.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-08-057	A.2.1.39 A.3.1.39 B.1.40 Audit item 509
29	Enhance the Water Chemistry Control – Primary and Secondary Program for IP2 to test sulfates monthly in the RWST with a limit of <150 ppb.	IP2: Complete	NL-07-039 NL-13-122	A.2.1.40 B.1.41
30	For aging management of the reactor vessel internals, IPEC will (1) participate in the industry programs for investigating and managing aging effects on reactor internals; (2) evaluate and implement the results of the industry programs as applicable to the reactor internals; and (3) upon completion of these programs, but not less than 24 months before entering the period of extended operation, submit an inspection plan for reactor internals to the NRC for review and approval.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-11-107	A.2.1.41 A.3.1.41

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
31	Additional P-T curves will be submitted as required per 10 CFR 50, Appendix G prior to the period of extended operation as part of the Reactor Vessel Surveillance Program.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-15-121	A.2.2.1.2 A.3.2.1.2 4.2.3
32	As required by 10 CFR 50.61(b)(4), IP3 will submit a plant-specific safety analysis for plate B2803-3 to the NRC three years prior to reaching the RT_{PTS} screening criterion. Alternatively, the site may choose to implement the revised PTS rule when approved.	IP3: Approximately 6 years after entering the PEO	NL-07-039 NL-07-140 NL-08-014 NL-08-127	A.3.2.1.4 4.2.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
33	At least 2 years prior to entering the period of extended operation, for the locations identified in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), under the Fatigue Monitoring Program, IP2 and IP3 will implement one or more of the following: (1) Consistent with the Fatigue Monitoring Program, Detection of Aging Effects, update the fatigue usage calculations using refined fatigue analyses to determine valid CUFs less than 1.0 when accounting for the effects of reactor water environment. This includes applying the appropriate Fen factors to valid CUFs determined in accordance with one of the following: 1. For locations in LRA Table 4.3-13 (IP2) and LRA Table 4.3-14 (IP3), with existing fatigue analysis valid for the period of extended operation, use the existing CUF. 2. Additional plant-specific locations with a valid CUF may be evaluated. In particular, the pressurizer lower shell will be reviewed to ensure the surge nozzle remains the limiting component. 3. Representative CUF values from other plants, adjusted to or enveloping the IPEC plant specific external loads may be used if demonstrated applicable to IPEC. 4. An analysis using an NRC-approved version of the ASME code or NRC-approved alternative (e.g., NRC-approved code case) may be performed to determine a valid CUF. (2) Consistent with the Fatigue Monitoring Program, Corrective Actions, repair or replace the affected locations before exceeding a CUF of 1.0.	IP2: Complete IP3: Complete	NL-07-039 NL-13-122 NL-07-153 NL-08-021 NL-10-082	A.2.2.2.3 A.3.2.2.3 4.3.3 Audit item 146
34	IP2 SBO / Appendix R diesel generator will be installed and operational by April 30, 2008. This committed change to the facility meets the requirements of 10 CFR 50.59(c)(1) and, therefore, a license amendment pursuant to 10 CFR 50.90 is not required.	Complete	NL-13-122 NL-07-078 NL-08-074 NL-11-101	2.1.1.3.5

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
35	Perform a one-time inspection of representative sample area of IP2 containment liner affected by the 1973 event behind the insulation, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Perform a one-time inspection of representative sample area of the IP3 containment steel liner at the juncture with the concrete floor slab, prior to entering the period of extended operation, to assure liner degradation is not occurring in this area. Any degradation will be evaluated for updating of the containment liner analyses as needed.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122 NL-11-101 NL-15-121 NL-09-018	Audit Item 27
36	Perform a one-time inspection and evaluation of a sample of potentially affected IP2 refueling cavity concrete prior to the period of extended operation. The sample will be obtained by core boring the refueling cavity wall in an area that is susceptible to exposure to borated water leakage. The inspection will include an assessment of embedded reinforcing steel. Additional core bore samples will be taken, if the leakage is not stopped, prior to the end of the first ten years of the period of extended operation. A sample of leakage fluid will be analyzed to determine the composition of the fluid. If additional core samples are taken prior to the end of the first ten years of the period of extended operation, a sample of leakage fluid will be analyzed.	IP2: Complete	NL-08-127 NL-11-101 NL-13-122 NL-09-056 NL-09-079	Audit Item 359
37	Enhance the Containment Inservice Inspection (CII-IWL) Program to include inspections of the containment using enhanced characterization of degradation (i.e., quantifying the dimensions of noted indications through the use of optical aids) during the period of extended operation. The enhancement includes obtaining critical dimensional data of degradation where possible through direct measurement or the use of scaling technologies for photographs, and the use of consistent vantage points for visual inspections.	IP2: Complete IP3: Complete	NL-08-127 NL-13-122	Audit Item 361

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
38	For Reactor Vessel Fluence, should future core loading patterns invalidate the basis for the projected values of RTpts or C_VUSE, updated calculations will be provided to the NRC.	IP2: Complete IP3: Complete	NL-08-143 NL-13-122 NL-15-121	4.2.1
39	Deleted		NL-09-079	
40	Evaluate plant specific and appropriate industry operating experience and incorporate lessons learned in establishing appropriate monitoring and inspection frequencies to assess aging effects for the new aging management programs. Documentation of the operating experience evaluated for each new program will be available on site for NRC review prior to the period of extended operation.	IP2: Complete IP3: Complete	NL-09-106 NL-13-122 NL-15-121	B.1.6 B.1.22 B.1.23 B.1.24 B.1.25 B.1.27 B.1.28 B.1.33 B.1.37 B.1.38
41	Deleted		NL-17-005	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
42	IPEC will develop a plan for each unit to 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. Option 1 (Analysis) IPEC will perform an analytical evaluation of the steam generator tube-to-tubesheet welds in order to establish a technical basis for either determining that the tubesheet cladding and welds are not susceptible to PWSCC, 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 a license amendment request. Option 2 (Inspection) IPEC will perform a one-time inspection of a representative number of tube-to-tubesheet welds in each steam generator to determine if PWSCC cracking is present. If weld cracking is identified: a. The condition will be resolved through repair or engineering evaluation to justify continued service, as appropriate, and b. An ongoing monitoring program will be established to perform routine tube-to-tubesheet weld inspections for the remaining life of the steam generators.	IP2: Complete IP3: Complete IP2: Not Applicable IP3: Not Applicable	NL-11-032 NL-11-074 NL-11-090 NL-11-096 NL-17-005	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
43	IPEC will review design basis ASME Code Class 1 fatigue evaluations to determine whether the NUREG/CR-6260 locations that have been evaluated for the effects of the reactor coolant environment on fatigue usage are the limiting locations for the IP2 and IP3 configurations. If more limiting locations are identified, the most limiting location will be evaluated for the effects of the reactor coolant environment on fatigue usage. IPEC will use the NUREG/CR-6909 methodology in the evaluation of the limiting locations consisting of nickel alloy, if any.	IP2: Complete IP3: Complete	NL-11-032 NL-13-122 NL-11-101 NL-15-121	4.3.3
44	IPEC will include written explanation and justification of any user intervention in future evaluations using the WESTEMS "Design CUF" module.	IP2: Complete IP3: Complete	NL-11-032 NL-11-101 NL-13-122 NL-15-121	N/A
45	IPEC will not use the NB-3600 option of the WESTEMS program in future design calculations until the issues identified during the NRC review of the program have been resolved.	IP2: Complete IP3: Complete	NL-11-032 NL-11-101 NL-13-122 NL-15-121	N/A
46	Include in the IP2 ISI Program that IPEC will perform twenty-five volumetric weld metal inspections of socket welds during each 10-year ISI interval scheduled as specified by IWB-2412 of the ASME Section XI Code during the period of extended operation. In lieu of volumetric examinations, destructive examinations may be performed, where one destructive examination may be substituted for two volumetric examinations.	IP2: Complete	NL-11-032 NL-11-074 NL-13-122	N/A
47	Deleted.		NL-14-093	N/A

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
48	Entergy will visually inspect IPEC underground piping within the scope of license renewal and subject to aging management review prior to the period of extended operation and then on a frequency of at least once every two years during the period of extended operation. This inspection frequency will be maintained unless the piping is subsequently coated in accordance with the preventive actions specified in NUREG-1801 Section XI.M41 as modified by LR-ISG-2011-03. Visual inspections will be supplemented with surface or volumetric non-destructive testing if indications of significant loss of material are observed. Consistent with revised NUREG-1801 Section XI.M41, such adverse indications will be entered into the plant corrective action program for evaluation of extent of condition and for determination of appropriate corrective actions (e.g., increased inspection frequency, repair, replacement).	IP2: Complete IP3: Complete	NL-12-174 NL-13-122 NL-15-121	N/A
49	Recalculate each of the limiting CUFs provided in section 4.3 of the LRA for the reactor vessel internals to include the reactor coolant environment effects (F_{en}) as provided in the IPEC Fatigue Monitoring Program using NUREG/CR-5704 or NUREG/CR-6909. In accordance with the corrective actions specified in the Fatigue Monitoring Program, corrective actions include further CUF re-analysis, and/or repair or replacement of the affected components prior to the CUF_{en} reaching 1.0.	IP2: Complete IP3: Complete	NL-13-052 NL-13-122 NL-15-121	A.2.2.2 A.3.2.2
50	Replace the IP2 split pins during the 2016 refueling outage (2R22).	IP2: Complete IP3: N/A	NL-13-122 NL-14-067	A.2.1.41 B.1.42
51	Enhance the Service Water Integrity Program by implementing LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-14-147.	IP2 & IP3: December 31, 2017	NL-14-147	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-16-122	IP2 & IP3: December 31, 2017	NL-16-122	A.2.1.33 A.3.1.33 B.1.34

#	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE	RELATED LRA SECTION / AUDIT ITEM
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-052	IP2 & IP3: December 31, 2017	NL-17-052	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-155	IP2 & IP3: December 31, 2018	NL-17-155	A.2.1.33 A.3.1.33 B.1.34
	Implement LRA Sections A.2.1.33, A.3.1.33 and B.1.34, as shown in NL-17-161	IP2 & IP3: December 31, 2018	NL-17-161	A.2.1.33 A.3.1.33 B.1.34
52	Implement the Coating Integrity Program for IP2 and IP3 as described in LRA Section B.1.42, as shown in NL-15-019.	IP2 & IP3: December 31, 2024	NL-15-019	A.2.1.42 A.3.1.42 B.1.43
53	Revise Bolting Integrity Program to include visual inspection of a representative sample of closure bolting (bolt heads, nuts, and threads) from components with an internal environment of a clear gas, such as air or nitrogen. A representative sample will be 20 percent of the population (for each bolting material and environment combination) up to a maximum of 25 fasteners during each 10-year period of the period of extended operation. The inspections will be performed when the bolting is removed to the extent that the bolting threads and bolt heads are accessible for inspections that cannot be performed during visual inspection with the threaded fastener installed.	May 31, 2018	NL-17-053	A.2.1.2 A.3.1.2 B.1.2
54	Enhance the Steam Generator Integrity Program as follows. • Revise applicable procedures to specify a general visual inspection of the steam generator channel head.	December 31, 2017	NL-17-060	A.2.1.34 A.3.1.34 B.1.35
55	Revise the Buried Piping and Tanks Inspection Program for IP2 and IP3 to incorporate the changes shown in LAR Sections A.2.1.5 and A.3.1.5 in letter NL-17-084.	December 31, 2017	NL-17-084	A.2.1.5 A.3.1.5