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GNRO-2014/00030

May 13, 2014

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

SUBJECT: Response to Request for Additional Information (RAI) dated January 2, 2014
Grand Gulf Nuclear Station, Unit 1
Docket No. 50-416
License No. NPF-29

REFERENCE: U.S. NRC Letter, "Requests for Additional Information for the Review of the Grand Gulf Nuclear Station, License Renewal Application," dated January 2, 2014

Dear Sir or Madam:

Entergy Operations, Inc is providing, in Attachment 1, the response to the referenced Request for Additional Information (RAI). Attachment 2 contains changes to the License Renewal Application (LRA) as a result of the responses to the above RAIs. Attachment 3 includes additional changes to the LRA that were identified during project document updates not associated with the RAI responses.

If you have any questions or require additional information, please contact James Nadeau at 601-437-2103.

I declare under penalty of perjury that the foregoing is true and correct. Executed on the 13th day of May, 2014.

Sincerely,

KJM/jas

Attachments and cc: (see next page)

Attachments:
1 Response to Request for Additional Information (RAI)
2 LRA Changes Due to Responses to Requests for Additional Information
3 Additional LRA Changes

cc: with Attachments

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Attachment 1 to

GNRO-2014/00030

Response to Request for Additional Information (RAI)

The format for the Requests for Additional Information (RAI) responses below is as follows. The RAI is listed in its entirety as received from the Nuclear Regulatory Commission (NRC) with background, issue and request subparts. This is followed by the Grand Gulf Nuclear Station (GGNS) RAI response to the individual question.

RAI 3.0.3-1

Background:

Recent industry operating experience (OE) and questions raised during the staffs review of several License Renewal Applications (LRAs) has resulted in the staff concluding that several Aging Management Programs (AMP) and Aging Management Review (AMR) items in the LRA may not or do not account for OE involving recurring internal corrosion, corrosion occurring under insulation, managing aging effects of fire water system components, and certain other issues covered by recommendations in NUREG 1801, "Generic Aging Lessons Learned (GALL) Report," AMP XI.M29, "Aboveground Metallic Tanks." In order to provide updated guidance, the NRC staff has issued LR-ISG-2012-02, "Aging Management of Internal Surfaces, Service Level III and Other Coatings, Atmospheric Storage Tanks, and Corrosion Under Insulation" (ADAMS Accession No. ML 13227A361).

Issue:

The staff noted that the applicant may not have incorporated the updated guidance into its AMPs.

Request:

Please provide details on how the updated guidance of LR-ISG-2012-02 has been accounted for in your AMPs, or provide adequate justification why incorporation is not required.

RESPONSE TO RAI 3.0.3-1

A response follows for each of the eight sections of LR-ISG-2012-02.

Response to LR-ISG section A "Recurring Internal Corrosion."

Based on the results of a review of the past five years of plant-specific operating experience, microbiologically influenced corrosion (MIC) of piping components is a recurring internal corrosion (RIC) issue as defined in LR-ISG 2012-02, Section A. Loss of material due to MIC leading to through-wall leaks has occurred at least once in each of two refueling cycles in the last five years.

Entergy monitors loss of material due to MIC in piping components at GGNS and replaces pipe where necessary. MIC is monitored in piping components of the following systems.

- Circulating water system – N71
- Standby service water system – P41
- Plant service water system – P44
- Fire protection system – P64

Monitoring of MIC degradation is performed using ultrasonic (UT) or radiographic (RT) measurements to determine wall thickness at selected locations. The locations selected for measurement provide a representative sample of the piping system. They are chosen based on pipe configuration (horizontal pipe, vertical pipe, pipe connections such as tees); flow conditions (low or moderate flow, stagnant, intermittent flow, stagnant flow in branch close to main line flow); and operating history (known degradation). Inspection locations are added or deleted as new information, e.g., changes in system operations, becomes available.

The wall thickness measurements at each selected location are compared to the nominal pipe wall thickness (for initial measurements) or to previous thickness measurements to determine rates of corrosion and the estimated time to reach T_{marg}. T_{marg} is the code minimum wall thickness plus a thickness margin equal to the expected wall loss during one refueling cycle. Subsequent measurements are performed as determined necessary based on the rate of corrosion and expected time to reach T_{marg}. In the last five years, approximately 60 inspections have been performed. A minimum of five MIC degradation inspections per refueling cycle will be performed until MIC no longer meets the criteria for recurring internal corrosion.

Components are replaced, if necessary, based on the rate of corrosion and the difference between measured wall thickness and T_{marg}. If wall thickness is found less than T_{marg}, the issue is entered into the corrective action program for resolution. Entergy considers multiple MIC locations in the technical evaluation of the structural integrity of the pipe when identified by volumetric MIC inspections.

MIC degradation monitoring has been effective in identifying internal piping corrosion. Neither pipe leaks nor pipe wall thinning, including the consideration of structural integrity, has resulted in the loss of a component's ability to support system pressure and flow requirements. MIC induced leakage from piping onto nearby safety-related equipment has not resulted in the loss of any safety function.

The standby service water system (P41) and the fire protection system (P64) include sections of buried piping that are not readily inspected for MIC degradation. However, new technologies for inspecting buried piping to identify internal corrosion are being developed and are expected to be significantly improved before the end of the current license term for GGNS. Prior to the period of extended operation (PEO), Entergy will select an inspection method (or methods) that will provide suitable indication of piping wall thickness for a representative sample of buried piping locations to supplement the existing inspection locations.

Although underground leaks are possible, leaks large enough to affect the function of these systems are expected to develop slowly. Such leaks are detectable by changes in system performance (e.g., changes in instrumentation readings or reduced cooling capacity), changes in system operation (e.g., more frequent jockey pump operation), or by the appearance of wetted ground around the leak. This is based on that the significant aging mechanism of concern is MIC and that it is a slow progression degradation process that occurs in isolated areas i.e. pitting that does not result in significant overall degradation of the component but would result in pin hole leaks that are easily identified and managed.

The Periodic Surveillance and Preventive Maintenance Program described in LRA B.1.35 will be augmented to incorporate the MIC degradation monitoring activities.

Revisions to LRA Sections A.1.35, B.1.35, and Section 3.3 and 3.4 tables are provided in Attachment 2.

Response to LR-ISG section B "Representative Minimum Sample Size for Periodic Inspections in GALL Report AMP XI.M38, 'Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components'."

This LR-ISG section recommends a change to the Internal Surfaces in Miscellaneous Piping and Ducting Components Program that provides for a minimum sample size. The program originally described in GGNS LRA B.1.26 specified only opportunistic inspections. Revisions to LRA Sections A.1.26 and B.1.26 are provided in Attachment 2.

Response to LR-ISG section C "Flow Blockage of Water-Based Fire Protection System Piping."

Entergy will perform the tests and inspections for fire water system blockage at GGNS as recommended by LR-ISG-2012-02, with exceptions listed in the revised LRA Section B.1.21 provided in Attachment 2.

Revisions to LRA Sections A.1.21, B.1.21, and Section 3.3 and 3.4 tables are provided in Attachment 2.

Response to LR-ISG section D "Revisions to the scope and inspection recommendations of GALL Report AMP XI.M29, "Aboveground Metallic Tanks."

The Aboveground Metallic Tanks Program described in GGNS LRA B.1.2 will manage the aging effects for tanks in the scope of the program consistent with the guidance of LR-ISG-2012-02. There are no indoor tanks within the scope of this program as defined in the ISG.

The only outdoor tank within the scope of the program is the condensate storage tank.

The Aboveground Metallic Tanks Program does not manage the effects of aging on the fire water storage tanks. The Fire Water System Program (described in LRA sections A.1.21 and B.1.21) manages the effects of aging on the fire water storage tanks in accordance with the recommendations of the LR-ISG.

Revisions to LRA Sections A.1.2, B.1.2, and Section 3.4 tables are provided in Attachment 2.

Response to LR-ISG section E "Corrosion Under Insulation."

The following discusses each applicable lettered paragraph under the summary of changes in LR-ISG-2012-02 Section E regarding corrosion under insulation.

a. LR-ISG-2012-02, Section E.iii.a recommends periodic inspections during each 10-year period of the PEO. GGNS inspections will be conducted during each 10-year period of the PEO.
b. LR-ISG-2012-02, Section E.iii.b recommends removal of insulation and inspection of component surfaces, except for tanks. For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of component surfaces. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type

(e.g., steel, stainless steel, copper alloy, aluminum) or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type. There are no in-scope outdoor insulated mechanical components.

c. LR-ISG-2012-02, Section E.iii.c recommends removal of insulation and inspection of tank surfaces. There are no in-scope outdoor insulated tanks or indoor insulated tanks operated below the dew point.

d. LR-ISG-2012-02, Section E.iii.d recommends inspection locations. Inspection locations will be based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for long periods of time below the dew point.

   Subsequent inspections will consist of an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.

   No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and

   No evidence of cracking

   If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.

e. LR-ISG-2012-02, Section E.iii.e discusses tightly adhering insulation. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of other types of insulation. These inspections will not be credited towards the inspection quantities for other types of insulation.

Revisions to LRA Sections A.1.18, B.1.18, and Section 3.3 and 3.4 tables are provided in Attachment 2.

<u>Response to LR-ISG section F "External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, 'Buried and Underground Piping and Tanks'."</u>

This LR-ISG section changes the recommendations of NUREG-1801, Section XI.M38 with respect to internal surfaces of buried and underground piping. LR-ISG-2012-02, Section F identifies that the condition of internal surfaces of buried and underground piping may be based on inspections of the interior surfaces of accessible piping where the material, environment, and aging effects of the buried or underground component are similar to those of the accessible component. If inspections of the interior surfaces of accessible components with material, environment, and aging effects similar to those of the interior surfaces of buried or underground components are not conducted, internal visual or external volumetric inspections will be conducted on the buried or underground piping.

The GGNS program corresponding to NUREG-1801, Section XI.M38, is the Internal Surfaces in Miscellaneous Piping and Ducting Components Program described in LRA Section A.1.26 and B.1.26. There are no buried and underground components with internal surfaces managed by the Internal Surfaces in Miscellaneous Piping and Ducting Components Program. Thus, no changes to the GGNS LRA are necessary to account for the guidance of this section of the LR-ISG.

Response to LR-ISG section G "Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38."

This LR-ISG section recommends changes to the aging management program of NUREG-1801, Section XI.M38 to clarify the intent of the pressure test option for elastomer inspections. The GGNS AMP corresponding to NUREG-1801, Section XI.M38 is the Internal Surfaces in Miscellaneous Piping and Ducting Components Program described in LRA Sections A.1.26 and B.1.26. Revisions to GGNS LRA A.1.26 and B.1.26 reflecting the recommended changes are provided in Attachment 2.

Response to LR-ISG section H "Key Miscellaneous Changes to the GALL Report and SRP-LR."

The updated guidance of this LR-ISG section was reviewed with respect to the GGNS LRA. Section H, subsection v, item e was the only item identified with a potential impact on the GGNS LRA. This item added a new aging effect for NUREG-1801. "Reduced thermal insulation resistance" in jacketed insulation of various types exposed to indoor or outdoor air was added for steam and power conversion systems.

Entergy reviewed the steam and power conversion systems piping at GGNS. Piping insulation is not credited for thermal resistance in support of any safety function of these systems. Consequently, reduction of thermal insulation resistance is not an aging effect requiring management, and no changes to the GGNS LRA are necessary to account for the guidance of this section of the LR-ISG.

RAI 3.0.3-2

Background:

Recent industry operating experience (OE) and questions raised during the staff's review of several License Renewal Applications (LRAs) has resulted in the staff concluding that several Aging Management Programs (AMP) and Aging Management Review (AMR) items in the LRA may not or do not account for recent OE regarding loss of coating integrity for Service Level III and other coatings.

Issue:

Industry OE indicates that degraded coatings have resulted in unanticipated or accelerated corrosion of the base metal and degraded performance of downstream equipment (e.g., reduction in flow, drop in pressure, reduction in heat transfer) due to flow blockage. Based on these industry OE examples, the staff has questions related to how the aging effect, loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage (e.g., cavitation damage downstream of a control valve), would be managed for Service Level III and Other coatings.

For purposes of this RAI:

1. Service Level III coatings are those installed on the interior of in-scope piping, heat exchanges, and tanks which support functions identified under 10 CFR 54.4(a)(1) and (a)(2).

2. "Other coatings," include coatings installed on the interior of in-scope piping, heat exchangers, and tanks whose failure could prevent satisfactory accomplishment of any of the functions identified under 10 CFR 54.4(a)(3).

The term 'coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfacers (e.g., concrete-lined fire water system piping as described in the "Safety Evaluation Report with Open Items Related to the License Renewal of Grand Gulf Nuclear Station, Unit 1 ," (SER) Section 3.0.3.1.20) that are designed to adhere to a component to protect its surface.

3. The terms "paint" and "linings" should be considered as coatings.

The staff believes that to effectively manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage of Service Level III and Other coatings an aging management program should include:

1. Baseline visual inspections of coatings installed on the interior surfaces of in-scope components should be conducted in the 10-year period prior to the period of extended operation.

2 Subsequent periodic inspections where the interval is based on the baseline inspection results. For example:

   a. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections could be conducted after multiple refueling outage intervals (e.g., for example six years, or more if the same coatings are in redundant trains).

b. If the inspection results do not meet the above; but, a coating specialist has determined that no remediation is required, subsequent inspections could be conducted every other refueling outage interval.

c. If coating degradation is observed that required repair or replacement, or for newly installed coatings, subsequent inspections should occur over at least once during the next two refueling outage intervals to establish a performance trend on the coatings.

3. All accessible internal surfaces for tanks and heat exchangers should be inspected. A representative sample of internally coated piping components not less than 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination should be inspected.

4. Coatings specialists and inspectors should be qualified in accordance with an ASTM International standard endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," including staff guidance associated with a particular standard.

5. Monitoring and trending should include pre-inspection reviews of previous inspection results.

6. The acceptance criteria should include that indications of peeling and delamination are not acceptable. Blistering can be evaluated by a coating specialist; however, physical testing should be conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface.

<u>Request:</u>

If coatings have been installed on the internal surfaces of in-scope components (i.e., piping, piping subcomponents, heat exchangers, and tanks), state how loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage will be managed, including:

1. the inspection method
2. the parameters to be inspected
3. when inspections will commence and the frequency of subsequent inspections
4. the extent of inspections and the basis for the extent of inspections if it is not 100 percent
5. the training and qualification of individuals involved in coating inspections
6. how trending of coating degradation will be conducted
7. acceptance criteria
8. corrective actions for coatings that do not meet acceptance criteria, and
9. the program(s) that will be augmented to include the above activities.

If necessary, provide revisions to LRA Section 3 Table 2s, Appendix A, and Appendix B. Note: draft RAIs 3.0.3-3, 3.0.3-4, 3.0.3-5, and 3.0.3-6 have been incorporated into RAI 3.0.3-1 due to issuance of LR-ISG-2012-02.

RESPONSE TO RAI 3.0.3-2

Coatings are installed on the internal surfaces of components subject to aging management review. Although applicable aging effects were identified for these components during the integrated plant assessment regardless of whether preventive features such as coatings were applied, activities to implement the recommendations provided in this RAI are discussed below.

1. Visual inspections are used to assess component internal coating condition.
2. The parameter to be monitored is the coated component internal surface condition.
3. Initial inspections will begin during the 10-year period prior to the period of extended operation but no later than the last scheduled refueling outage prior to the period of extended operation. Subsequent inspections will be performed based on the initial inspection results. For example:

    i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If no indications are found during inspection of one train, the redundant train need not be inspected. The subsequent inspection will be on the redundant train.

    ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

    Inspections of coatings that are repaired, replaced or newly installed are not periodic activities performed to manage the effects of aging. Such inspections confirm adequacy of application of protective coatings which is not an activity necessary to manage the effects of aging in accordance with the license renewal rule.

4. The extent of inspections for all coated tanks and heat exchangers is all accessible internal surfaces. The visible portions of coated tanks and heat exchangers are inspected upon disassembly or entry. The extent of inspections for internally coated piping is a representative sample: either 73 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination. The basis for the 73 inspection locations or 50 percent of the pipe length is to provide a close approximation of a 95 percent confidence level that 95 percent of a given population is not experiencing loss of coating integrity.
5. Coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." Subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist."
6. Preventive maintenance activities provide for monitoring and trending of aging degradation. Inspection intervals are established such that they provide for timely detection of component degradation. Inspection intervals are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations.

7. Peeling and delamination are not permitted. Cracking is not permitted if accompanied by delamination or loss of adhesion. Blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. In the event peeling, delamination, cracking, or loss of adhesion is identified, follow-up evaluations such as an adhesion test will be performed. In the event the base metal is exposed and the visual inspection identifies accelerated corrosion, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its intended function until the next projected inspection.
8. Corrective actions for unacceptable inspection findings will be determined in accordance with the GGNS 10 CFR 50 Appendix B Corrective Action Program (CAP).
9. The Periodic Surveillance and Preventive Maintenance Program described in LRA B.1.35 is enhanced to include verification of coating integrity of applicable piping, tanks and heat exchangers, coating acceptance criteria, qualifications for personnel performing coating inspections and evaluating coating findings, and documentation of coating inspections.

   The Fire Water System Program described in LRA B.1.21 is enhanced in the response to GGNS RAI 3.0.3-1 Issue C to address the coatings in the fire water storage tanks.

   The Service Water Integrity Program described in LRA B.1.41 is enhanced to include verification of internal coating integrity of applicable piping, coating acceptance criteria, qualifications for personnel performing coating inspections and evaluating coating findings, and documentation of coating inspections.

Revisions to LRA Sections A.1.35, A.1.41, B.1.35, B.1.41, and Section 3.3 and 3.4 tables are provided in Attachment 2.

Attachment 2 to

GNRO-2014/00030

LRA Changes Due to Responses to Requests for Additional Information

Revisions to text and tables in LRA Sections 3.3 and 3.4 are provided below with additions underlined and deletions marked through.

Table 3.3.1: Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-64	Steel, copper alloy piping, piping components, and piping elements exposed to raw water	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Consistent with NUREG-1801 <u>for most components</u>. Loss of material for steel and copper alloy Fire Protection system components exposed to raw water is managed by the Fire Water System Program. <u>For steel and copper alloy fire protection system components that do not have a 10 CFR 54.4 (a)(3) fire protection function, and are outside the scope of the Fire Water System Program, the Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages loss of material.</u>
3.3.1-67	Steel tanks exposed to air – outdoor (external)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	~~Consistent with NUREG-1801.~~ Loss of material for <u>the</u> steel <u>fire water storage</u> tank~~s~~ exposed to outdoor air is managed by the ~~Aboveground Metallic Tanks~~ <u>Fire Water System</u> Program.

Table 3.3.1: Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-78	Steel piping and components (external surfaces), ducting and components (external surfaces), ducting; closure bolting exposed to air – indoor, uncontrolled (external), air – indoor, uncontrolled (external), air – outdoor (external), condensation (external)	Loss of material due to general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	Loss of material for most steel components exposed to indoor air, outdoor air or condensation is managed by the External Surfaces Monitoring Program. The Fire Protection Program manages loss of material for steel components of the Halon and CO_2 fire suppression systems exposed to outdoor air. The Fire Water System Program manages loss of material for the steel fire water storage tank exposed to outdoor air. The Service Water Integrity Program manages loss of material for steel components of the standby service water system exposed to outdoor air that are not routinely accessible for inspection under the External Surfaces Monitoring Program.

At the end of LRA Table 3.3.1 Auxiliary Systems, in **Notes for Table 3.3.2-1 through Table 3.3.2-19-37**, add the following Plant Specific Note 310.

310. Program provisions for indoor insulated components that operate below the dew point apply.

Add the following line to **LRA Table 3.3.2-5, Combustible Gas Control System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (Bonnet)	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Add the following lines to **LRA Table 3.3.2-7, Standby Service Water System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310
Piping components	Pressure boundary	Carbon steel, stainless steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance	--	--	H
Piping	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (Int)	Loss of coating integrity	Service Water Integrity	-	-	H

Add the following lines to **LRA Table 3.3.2-9, Plant Service Water System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (Bonnet)	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (Int)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310
Piping components	Pressure boundary	Carbon steel, stainless steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance	--	--	H

Revise and add the following lines in **LRA Table 3.3.2-12, Fire Protection – Water System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance	--	--	H
Piping	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Fuel oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H
Tank	Pressure boundary	Carbon steel	Air – indoor (ext)	Loss of material	~~External Surfaces Monitoring~~ Fire Water System	VII.I.A-77	3.3.1-78	~~A~~ E
Tank	Pressure boundary	Carbon steel	Air – outdoor (ext)	Loss of material	~~Aboveground Metallic Tanks~~ Fire Water System	VII.H1.A-95	3.3.1-67	~~C~~ E
Tank	Pressure boundary	Carbon steel	Concrete (ext)	Loss of material	~~Aboveground Metallic Tanks~~ Fire Water System	VIII.E.SP-115	3.4.1-30	~~C~~ E
Tank	Pressure boundary	Carbon steel	Soil (ext)	Loss of material	~~Aboveground Metallic Tanks~~ Fire Water System	VIII.E.SP-115	3.4.1-30	~~C~~ E
Tank	Pressure boundary	Carbon steel	Condensation (int)	Loss of material	Fire Water System	VII.F1.A-08	3.3.1-90	E

Add the following lines to **LRA Table 3.3.2-14, Plant Chilled Water System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following lines to **LRA Table 3.3.2-15, Standby Diesel Generator System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Fuel oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Lube oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following line to **LRA Table 3.3.2-16, HPCS Diesel Generator System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Fuel oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following lines to **LRA Table 3.3.2-17, Control Room Heating, Ventilation, and Air Conditioning System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger (Bonnet)	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (Int)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Copper alloy	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310

Add the following line to **LRA Table 3.3.2-19-7, Reactor Water Cleanup System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Add the following line to **LRA Table 3.3.2-19-9, CRD Maintenance Facility, Flush Tank Filter and Leak Test System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Add the following lines to **LRA Table 3.3.2-19-14, Make Up Water Treatment System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310

Add the following lines to **LRA Table 3.3.2-19-15, Process Sampling System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Insulated piping, piping components	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 310

Add the following lines to **LRA Table 3.3.2-19-16, Standby Service Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance	--	--	H
Piping	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (Int)	Loss of coating integrity	Service Water Integrity	-	-	H
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (int.)	Loss of coating integrity	Service Water Integrity	-	-	H

Add the following line to **LRA Table 3.3.2-19-17, Component Cooling Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following line to **LRA Table 3.3.2-19-18, Turbine Building Cooling Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following line to **LRA Table 3.3.2-19-19, Plant Service Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping components	Pressure boundary	Carbon steel, stainless steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance	--	--	H

Revise and add the following lines in **LRA Table 3.3.2-19-23, Fire Protection System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Filter housing	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-33	3.3.1-64	~~A~~ E
Nozzle	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-33	3.3.1-64	~~A~~ E
Piping	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-33	3.3.1-64	~~A~~ E
Piping	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (int)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H
Piping components	Pressure boundary	Carbon steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance Program	-	-	H
Strainer housing	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-33	3.3.1-64	~~A~~ E

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Valve body	Pressure boundary	Carbon steel	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-33	3.3.1-64	~~A~~ E
Valve body	Pressure boundary	Copper alloy > 15% Zn or > 8% Al	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.AP-197	3.3.1-64	~~A~~ E
Valve body	Pressure boundary	Gray cast iron	Raw water (int)	Loss of material	~~Fire Water System~~ Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.G.A-33	3.3.1-64	~~A~~ E

Add the following line to **LRA Table 3.3.2-19-24, Domestic Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following line to **LRA Table 3.3.2-19-25, Plant Chilled Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

Add the following lines to **LRA Table 3.3.2-19-26 Drywell Chilled Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 310
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Add the following line to **LRA Table 3.3.2-19-27, Standby Diesel Generator System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Fuel oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance	-	-	H

3.4.2.2.2 Cracking due to Stress Corrosion Cracking (SCC)

Cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air, including air which has recently been introduced into buildings, such as near intake vents. The outside air at the GGNS site is not conducive to stress corrosion cracking. The GGNS site is not near a saltwater coastline and is not near highways treated with salt in the wintertime. Soil in the vicinity of the site contains no more than trace quantities of chlorides. The GGNS site is in an isolated location, away from agricultural or industrial sources of chloride contamination. The GGNS cooling tower uses water treated with hypochlorite solution; however, cooling tower drift rarely settles near plant equipment. Nevertheless, consistent with NUREG-1801, cracking of most stainless steel components directly exposed to outdoor air is identified as an aging effect requiring management and is managed by the External Surfaces Monitoring Program. Consistent with LR-ISG-2012-02, the Aboveground Metallic Tanks Program manages cracking on the external surface of the stainless steel condensate storage tank exposed to outdoor air. At GGNS, there are no stainless steel components of the steam and power conversion systems included in the scope of license renewal that are located near unducted air intakes.

Table 3.4.1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-2	Stainless steel piping, piping components, and piping elements; tanks exposed to air – outdoor	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated	Consistent with NUREG-1801 for most components. Cracking of stainless steel components exposed to outdoor air is managed by the External Surfaces Monitoring Program. Consistent with LR-ISG-2012-02, the Aboveground Metallic Tanks Program manages cracking on the external surface of the stainless steel condensate storage tank exposed to outdoor air. See Section 3.4.2.2.2
3.4.1-30	Steel, stainless steel, aluminum tanks exposed to soil or concrete, air – outdoor (external)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Consistent with NUREG-1801 for some components. Loss of material for steel tanks exposed to concrete and stainless steel tanks exposed to outdoor air is managed by the Aboveground Metallic Tanks Program. There are no aluminum tanks or tanks exposed to soil in the steam and power conversion systems in the scope of license renewal. The Fire Water System Program manages loss of material for the fire water storage tank exposed to concrete and soil.

At the end of LRA Table 3.4.1 Steam and Power Conversion Systems, in **Notes for Table 3.4.2-1 through 3.4.2-2-19**, add the following Plant Specific Note 404.

404. Program provisions for indoor insulated components that operate below the dew point apply.

Revise the following line in **LRA Table 3.4.2-1, Condensate and Refueling Water Storage and Transfer System Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Stainless steel	Air – outdoor (ext)	Cracking	~~External Surfaces Monitoring~~ Aboveground Metallic Tanks	VIII.E.SP-118	3.4.1-2	~~A~~ E

Add the following line to **LRA Table 3.4.2-2-3, Condensate and Feedwater System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Add the following line to **LRA Table 3.4.2-2-4, Condensate Cleanup System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Add the following line to **LRA Table 3.4.2-2-5 Heater, Vents, and Drains System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404

Add the following line to **LRA Table 3.4.2-2-18 Circulating Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping components	Pressure boundary	Carbon steel, stainless steel	Raw water (int)	Recurring internal corrosion	Periodic Surveillance and Preventive Maintenance	--	--	H

Revisions to LRA Section A.1.2 are provided below with additions underlined and deletions marked through.

A.1.2 Aboveground Metallic Tanks Program

The Aboveground Metallic Tanks Program includes outdoor tanks situated on soil or concrete. The program includes preventive measures to mitigate corrosion by protecting the external surfaces of steel components per standard industry practice including the use of sealant or caulking at the concrete to tank interface of outdoor tanks. External visual examinations (supplemented with physical manipulation of caulking or sealant) are performed to monitor degradation of uncoated surfaces and of protective paint, coating, and caulking, or sealant. Surface exams are conducted to detect cracking when susceptible materials are used (e.g., stainless steel, aluminum). A sample of the external surfaces of insulated tanks are inspected. Internal visual and surface (when necessary to detect cracking) examinations are conducted as well as measuring the thickness of the tank bottoms to ensure that significant degradation is not occurring and that the component intended function is maintained during the period of extended operation. ~~manages loss of material for the outer surfaces, ncluding the bottom surfaces, of above ground metallic tanks constructed on concrete or soil, using periodic visual inspections, measurements of the thickness of the tank bottoms, and preventive measures such as protective coatings and sealants. Tanks are inspected externally at least once every refueling cycle. In addition, ultrasonic testing (UT) thickness measurements of the tank bottoms will be performed at least once within the 5 years prior to the period of extended operation and whenever the tanks are drained during the period of extended operation~~

The following table provides tank inspection details[1].

Material	Environment	AERM	Inspection Technique[2]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[3], and bottom Inside Surface (IS), Outside Surface (OS)[4, 5]				
Stainless steel	Treated water	Loss of Material	Visual from IS or Volumetric from OS[6]	One-time inspection conducted in accordance with section B.1.33[7]
Inspections to identify degradation of external surfaces of tank roof, tank shell, and bottom not exposed to soil or concrete[8]				
Stainless steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[9, 10]	Each 10-year period starting 10 years before the period of extended operation
Inspections to identify degradation of external surfaces of tank bottoms and tank shells exposed to soil or concrete				
Stainless steel	Soil or concrete	Loss of material	Volumetric from IS[11]	Each 10-year period starting 10 years before the period of extended operation[12]

Table Notes - Tank Inspection Recommendations

1. When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period before the start of the period of extended operation.
2. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated to be effective at detecting the aging effect requiring management (AERM) and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If followup ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.
3. Nonwetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal waterline) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM.
4. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces.
5. For tank configurations in which deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the internal inspections of the tank's bottom should include inspections of the side wall of the tank up to the top of the sludge-affected region.
6. At least 25 percent of the tank's internal surface is to be inspected using a method capable of precisely determining wall thickness. The inspection method should be capable of detecting both general and pitting corrosion and be demonstrated effective by the applicant.
7. At least one tank for each material and environment combination should be inspected. The tank inspection can be credited towards the sample population for one time inspection in accordance with section B.1.33.
8. For insulated tanks, the external inspections of tank surfaces that are insulated are conducted in accordance with the sampling recommendations in this aging management program (AMP). If the initial inspections meet the criteria described in the preceding "Alternatives to Removing Insulation" portion of this AMP, subsequent inspections may consist of external visual inspections of the jacketing in lieu of surface examinations. Tanks with tightly adhering insulation may use the "Alternatives to Removing Insulation" portion of this AMP for initial and all follow-on inspections.
9. A one-time inspection conducted in accordance with section B.1.33 may be conducted in lieu of periodic inspections if an evaluation conducted before the PEO and during each 10-year period during the PEO demonstrates the absence of environmental impacts in the vicinity of the plant due to: (a) the plant being located within approximately 5 miles of a saltwater coastline, or within 1/2 mile of a highway that is treated with salt in the wintertime, or in areas in which the soil contains more than trace amounts of chlorides, (b) cooling towers where the water is treated with chlorine or chlorine compounds, and (c) chloride contamination from other agricultural or industrial sources. The evaluation should include soil sampling in the vicinity of the tank (because soil results indicate atmospheric fallout accumulating in the soil and potentially affecting tank surfaces) and sampling of residue on the top and sides of the tank to ensure that chlorides or other deleterious compounds are not present at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking.
10. A minimum of either 25 sections of the tank's surface (e.g., 1-square-foot sections for tank surfaces, 1-linear-foot sections of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed in such a way that inspections occur in those areas most susceptible to degradation (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).
11. When volumetric examinations of the tank bottom cannot be conducted because the tank is coated, an exception should be stated, and the accompanying justification for not conducting inspections should include the considerations in footnote 13, below, or propose an alternative examination methodology.
12. A one-time inspection conducted in accordance with section B.1.33 may be conducted in lieu of periodic inspections if an evaluation conducted before the PEO and during each 10-year period during the PEO demonstrates that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation should include soil sampling from underneath the tank.

Revisions to LRA Section A.1.18 are provided below with additions underlined and deletions marked through.

A.1.18 External Surfaces Monitoring Program

The External Surfaces Monitoring Program manages aging effects through visual inspection of external surfaces for evidence of loss of material, cracking and change in material properties. Physical manipulation to detect hardening or loss of strength for elastomers and polymers is also used.

The External Surfaces Monitoring Program will be enhanced as follows.

- Include instructions for monitoring aging effects for flexible polymeric components through manual or physical manipulation of the material, with a sample size for manipulation of at least 10 percent of available surface area.
- Clearly identify underground components within the scope of this program in program documents. Underground components are those for which access is physically restricted.
- Provide instructions for inspecting all underground components within the scope of this program during each 5-year period, beginning 10 years prior to the entry into the period of extended operation.
- Revise External Surfaces Monitoring Program procedures to specify the following for insulated components.
  - Periodic representative inspections will be conducted during each 10-year period during the PEO.
  - For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of the component surface. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type.
  - Inspection locations will be based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for longer periods of time below the dew point.

    Subsequent inspections can be limited to an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection.

    - No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and

➢ No evidence of cracking

If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above.

- Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of other types of insulation. These inspections will not be credited towards the inspection quantities for other types of insulation.

Revisions to LRA Section A.1.21 are provided below with additions underlined and deletions marked through.

A.1.21 Fire Water System Program

The Fire Water System Program manages loss of material and fouling for components in fire protection systems using preventive, inspection, and monitoring activities, including periodic full-flow flush tests, system performance testing, and testing or replacement of sprinkler heads. Applicable industry standards and guidance documents, including NFPA codes, are used to delineate the program. The program includes acceptance criteria for the water-based fire protection system to maintain required pressure, and acceptance criteria will be enhanced to verify no unacceptable degradation. Corrective action is initiated upon loss of system operating pressure, which is monitored continuously.

The Fire Water System Program will be enhanced as follows.

- Include periodic visual inspection of spray and sprinkler system internals for evidence of degradation. ~~Acceptance criteria will be enhanced to verify no unacceptable degradation.~~

- Revise Fire Water System Program procedures to include inspecting sprinklers in the overhead from the floor for signs of corrosion.

- Revise Fire Water System Program procedure to ~~I~~include periodic inspection of hose reels for degradation. ~~Acceptance criteria will be enhanced to verify no unacceptable degradation.~~

- Revise Fire Water System Program procedures to replace sprinklers that the tested sprinkler represents, if the tested sprinkler fails to meet the test acceptance criteria.

- Revise Fire Water System Program procedures to ensure the hydrant valve is opened fully and ensure the hydrant flows for not less than one minute during flow testing.

- Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following.

    - testing for possible voids beneath the tank
    - inspection of the vortex breaker
    - testing specified by Section 9.2.7 of NFPA-25 (2011 Edition) if a coating defect is identified
        - take dry film thickness measurements at random locations to determine the overall coating thickness as specified by NFPA-25 (2011 Edition) Section 9.2.6.4
        - perform a spot wet-sponge test to detect pinholes, cracks, or other compromises in the coating when specified in NFPA-25 (2011 Edition) Section 9.2.6.4
        - take nondestructive ultrasonic readings to evaluate the wall thickness where there is evidence of pitting or corrosion as specified by NFPA-25 (2011 Edition) Section 9.2.6.4
        - testing the tank bottom for metal loss or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion as specified by NFPA-25 (2011 Edition) Section 9.2.6.4

- Revise Fire Water System Program procedures to ensure there is no flow blockage by visually inspecting the charcoal filter deluge nozzles when the charcoal is replaced.

- ~~Include one of the following options.~~

  ~~(1) Wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material will be performed prior to the period of extended operation and periodically thereafter. 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.~~

  ~~OR~~

  ~~(2) A visual inspection of the internal surface of fire protection piping will be performed upon each entry to the system for routine or corrective maintenance. These inspections will be capable of evaluating (a) wall thickness to ensure against catastrophic failure and (b) the inner diameter of the piping as it applies to the design flow of the fire protection system. Maintenance history shall be used to demonstrate that such inspections have been performed on a representative number of locations prior to the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. Additional inspections will performed as needed to obtain this representative sample prior to the period of extended operation. The periodicity of inspections during the period of extended operation will be determined through an engineering evaluation of the operating experience gained from the results of previous inspections of fire water piping.~~

- Revise Fire Water System Program procedures to periodically open a flushing connection at the end of one main and remove a component such as a sprinkler toward the end of one branch line, five years prior to the PEO, and every five years during the PEO to perform a visual inspection in accordance with NFPA 25 (2011 Edition) Section 14.2.1.

- Include a visual inspection of a representative number of locations on the interior surface of below grade fire protection piping at a frequency of at least once every 10 years during the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. ~~Acceptance criteria will be no unacceptable degradation.~~

- Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with NFPA--25 (2011 Edition), Section 5.3.1. ~~Sprinkler heads will be tested or replaced. If testing is chosen a representative sample of sprinkler heads will be tested or replaced before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation. NFPA-25 defines a representative sample of sprinklers to consist of a minimum of not less than 4 sprinklers or 1 percent of the number of sprinklers per individual sprinkler sample, whichever is~~

~~greater. If replacement of the sprinklers is chosen, all sprinklers that have been in service for 50 years will be replaced.~~

- Revise Fire Water System Program procedures to inspect the strainers upstream of the deluge valves every three years.

- Revise Fire Water System Program procedures for flow testing, main drain testing, or internal inspection to specify an acceptance criterion of no debris observed (i.e., no corrosion products that are sufficient to obstruct flow or cause downstream components to become clogged).

- Revise Fire Water System Program procedures to specify replacing any sprinkler that shows signs of leakage or corrosion.

- Revise Fire Water System Program procedures to require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the Corrective Action Program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains and branch lines, and the performance of a complete flushing program by qualified personnel.

- Revise Fire Water System Program procedures to require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access.

Revisions to LRA Section A.1.26 are provided below with additions underlined.

A.1.26 Internal Surfaces in Miscellaneous Piping and Ducting Components Program

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages the effects of aging using opportunistic visual inspections of the internal surfaces of metallic piping, piping components, ducting, elastomeric components, and other components during periodic surveillances or maintenance activities when the surfaces are accessible for visual inspection.

To ensure a representative number of components are inspected, in each 10-year period during the period of extended operation (PEO), an assessment will be made of the opportunistic inspections completed during that period for each material-environment-aging effect combination within the scope of this program. Directed inspections will be conducted to ensure that an inspection sample size of 20 percent, with a maximum sample size of 25 inspections, is completed for each material-environment-aging effect combination during the 10-year period under review. Where practical, inspections shall be conducted at locations that are most susceptible to the effects of aging because of time in service, severity of operating conditions (e.g., low or stagnant flow), and lowest design margin. An inspection conducted of a material in a more severe environment may be credited as an inspection of the same material in a less severe environment.

The program inspections ensure that environmental conditions are not causing material degradation that could result in a loss of the component's intended function. For metallic components visual inspection will be used to detect loss of material and fouling. For elastomeric and plastic components, visual inspections will be used to detect cracking and change in material properties. Visual examinations of elastomeric components are accompanied by physical manipulation or pressurization (i.e., the component is sufficiently pressurized to expand the surface of the material in such a way that cracks or crazing are evident) such that changes in material properties are readily observable. The sample area subject to manipulation of flexible elastomeric components is at least 10 percent of the available surface area. The program manages the effects of aging for piping and components exposed to environments of air-indoor, air-outdoor, condensation, exhaust gas, lube oil, raw water, waste water, and treated water.

Revisions to LRA Section A.1.35 are provided below with additions underlined.

A.1.35 Periodic Surveillance and Preventive Maintenance Program

The Periodic Surveillance and Preventive Maintenance Program manages aging effects not managed by other aging management programs, including loss of material due to erosion, loss of material due to recurring internal corrosion, cracking, loss of coating integrity and change in material properties.

Inspections occur at least once every five years during the period of extended operation, with the exception of coating inspections for which frequency is based on coating condition. Visual or other NDE inspections of components in the low pressure core spray. residual heat removal, pressure relief. reactor core isolation cooling, high pressure core spray. and floor and equipment drains systems and the containment building gaskets/seals are performed every five years. Visual or other NDE inspections of a representative sample of internal surfaces of components in the control rod drive, circulating water, and floor and equipment drains systems are performed every five years. UT or other NDE wall thickness measurements of selected components of the circulating water, standby service water, component cooling water, plant service water and fire protection systems are performed periodically as necessary to assure minimum pipe wall thickness is maintained.

During the10-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces. Subsequent coating inspections will be performed based on inspection results as follows.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train need not be inspected during that inspection interval.
ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

Coating inspections will cover all accessible internal coated surfaces of applicable tanks and heat exchangers. For internal coatings of piping, inspections will cover 50 percent of coated piping within the system or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations of coated piping will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance.

Individuals performing coating inspections are certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants. Evaluators of inspection findings are nuclear coatings subject matter experts qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." An individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating degradation including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to a subsequent inspection or repair opportunity.

Loss of coating integrity acceptance criteria are (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. In the event peeling, delamination, cracking, or loss of adhesion is identified, follow-up evaluations such as knife adhesion test, or adhesion test will be performed. In the event the base metal is exposed and the visual inspection identifies accelerated corrosion, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its intended function until the next inspection or repair opportunity.

Credit for program activities has been taken in the aging management review of the following systems and structures.

- Gasket/seal for upper containment pool gates in containment building.
- Low pressure core spray system (LPCS) piping passing through the waterline region of suppression pool.
- Residual heat removal (RHR) system piping passing through the waterline region of suppression pool.
- Pressure relief system piping passing through the waterline region of the suppression pool.
- Reactor core isolation cooling (RCIC) system piping passing through the waterline region of the suppression pool.
- Control rod drive (CRD) system piping.
- Circulating water system piping and valve bodies.
- Floor and equipment drain system piping, drain housings, and valve bodies.
- Piping adjacent to the high pressure, intermediate pressure, and low pressure condenser shells in the circulating water system.
- High pressure core spray (HPCS) system piping passing through the waterline region of the suppression pool.
- Floor and equipment drain system piping below the waterline in the in-scope sumps.
- Moisture separator-reheater shell in the moisture separator-reheater vents and drains system.
- Piping components of the circulating water, standby service water, component cooling water, plant service water, and fire protection systems.
- Fire protection system internally coated piping
- Reactor water cleanup system internally coated tank
- CRD maintenance facility, flush tank filter and leak test system internally coated tanks
- Condensate and feedwater system internally coated tank
- Condensate cleanup internally coated tanks
- Component cooling water internally coated tank
- Turbine building cooling water internally coated tanks
- Domestic water system internally coated tank
- Plant chilled water system internally coated tank
- Drywell chilled water system internally coated heat exchanger and tank
- Standby diesel generator system internally coated tanks
- HPCS diesel generator system internally coated tanks
- Combustible gas control system internally coated heat exchangers

- Control room HVAC system internally coated heat exchangers

The Periodic Surveillance and Preventive Maintenance Program will be enhanced as follows.

- Revise program guidance documents 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.

Revisions to LRA Section A.1.41 are provided below with additions underlined.

A.1.41 Service Water Integrity Program

The Service Water Integrity Program manages loss of material and fouling in open-cycle cooling water systems as described in the GGNS response to NRC GL 89-13. The program also includes inspections for loss of material due to erosion and loss of internal coating integrity. In addition, the program includes inspections of coatings for submerged piping in the standby service water (SSW) basin. The frequency of these inspections is based on the inspection results.

During the10-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces of standby service water system components. Subsequent coating inspections will be performed based on inspection results as follows.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train need not be inspected during that inspection interval.
ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

The Service Water Integrity Program will be enhanced as follows.

- Revise Service Water Integrity Program documents to include inspections for loss of material due to erosion.
- Revise Service Water Integrity Program documents to include visual inspections for loss of coating Integrity during the 10-year period prior to the period of extended operation. Include provisions to specify subsequent coating inspections based on inspection results as follows.
  i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train need not be inspected during that inspection interval.

ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

- Visually inspect 50 percent of coated internal surfaces of piping or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance. Inspect all accessible coated internal surfaces of tanks.
- Include the following coating integrity acceptance criteria: (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. In the event peeling, delamination, cracking, or loss of adhesion is identified, follow-up evaluations such as knife adhesion test, or adhesion test will be performed. In the event the base metal is exposed and the visual inspection identifies accelerated corrosion, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its intended function until the next inspection or repair opportunity.
- Revise Service Water Integrity Program procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants," and that subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist."
- Revise Service Water Integrity Program procedures to ensure an individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection or repair opportunity.

Th~~is~~ese enhancements will be implemented prior to May 1, 2024

Revisions to LRA Section A.4 are provided below with additions underlined and deletions marked through.

Item Number	COMMITMENT	LRA SECTION	IMPLEMENTATION SCHEDULE	SOURCE
9	Enhance the External Surfaces Monitoring Program to include instructions for monitoring of the aging effects for flexible polymeric components through manual or physical manipulation of the material, including a sample size for manipulation of at least 10 percent of available surface area. Enhance the External Surfaces Monitoring Program as follows. 1. Underground components within the scope of this program will be clearly identified in program documents. 2. Instructions will be provided for inspecting all underground components within the scope of this program during each 5 year period, beginning 10 years prior to entering the period of extended operation. 3. <u>Revise External Surfaces Monitoring Program procedures to specify the following for insulated components.</u> • <u>Periodic representative inspections will be conducted during each 10-year period during the PEO.</u> • <u>For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of the component surface. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type.</u>	B.1.18	Prior to May 1, 2014 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2013/00021 <u>GNRO-2014/00030</u>

	• Inspection locations will be selected based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for longer periods of time below the dew point. Subsequent inspections can be limited to an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection. ➢ No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and ➢ No evidence of cracking If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. • Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation is considered a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of other types of insulation. These inspections will not be credited towards the inspection quantities for other types of insulation.			GNRO-2014/00030

Item Number	COMMITMENT	LRA SECTION	IMPLEMENTATION SCHEDULE	SOURCE
12	Revise Fire Water System Program procedures to include inspecting sprinklers in the overhead from the floor for signs of corrosion. ~~Enhance~~ Revise the Fire Water System Program procedure to include inspection of hose reels for degradation. ~~Acceptance criteria will be enhanced to verify no unacceptable degradation.~~ Revise Fire Water System Program procedures to replace sprinklers that the tested sprinkler represents, if the tested sprinkler fails to meet the test acceptance criteria. Revise Fire Water System Program procedures to ensure the hydrant valve is opened fully and ensure the hydrant flows for not less than one minute during flow testing. Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following. • testing for possible voids beneath the tank • inspection of the vortex breaker • testing required by Section 9.2.7 of NFPA-25 (2011 Edition) if a coating defect is identified ➢ take dry film thickness measurements at random locations to determine the overall coating thickness when specified by NFPA-25 (2011 Edition) Section 9.2.6.4 ➢ perform a spot wet-sponge test to detect pinholes, cracks, or other compromises in the coating when required by NFPA-25 (2011 Edition) Section 9.2.6.4 ➢ take nondestructive ultrasonic readings to evaluate the wall thickness where there is evidence of pitting or corrosion as specified in NFPA-25 (2011 Edition) Section 9.2.6.4 ➢ testing the tank bottom for metal loss or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion as specified by NFPA-25 (2011 Edition) Section 9.2.6.4 Revise Fire Water System Program procedures to ensure there is no flow blockage by visually inspecting the charcoal filter deluge nozzles when the charcoal is replaced.	B.1.21	Prior to May 1, 2024 or the end of the last refueling outage prior to November 1, 2024, whichever is later.	GNRO-2011/00093 GNRO-2014/00030

	~~Enhance the Fire Water Program to include one of the following options.~~ ~~(1) Wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material will be performed prior to the period of extended operation and at periodic intervals thereafter. 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.~~ ~~OR~~ ~~(2) A visual inspection of the internal surface of fire protection piping will be performed upon each entry to the system for routine or corrective maintenance. These inspections will be capable of evaluating (a) wall thickness to ensure against catastrophic failure and (b) the inner diameter of the piping as it applies to the design flow of the fire protection system. Maintenance history shall be used to demonstrate that such inspections have been performed on a representative number of locations prior to the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. Additional inspections will performed as needed to obtain this representative sample prior to the period of extended operation. The periodicity of inspections during the period of extended operation will be determined through an engineering evaluation of the operating experience gained from the results of previous inspections of fire water piping.~~ <u>Revise Fire Water System Program procedures to periodically open a flushing connection at the end of one main and remove a component such as a sprinkler toward the end of one branch line five years prior to the PEO, and every five years during the PEO to perform a visual inspection in accordance with NFPA 25 (2011 Edition) Section 14.2.1.</u> Enhance the Fire Water Program to include a visual inspection of a representative number of locations on the interior surface of below grade fire			~~GNRO-2012/00089~~

	protection piping in at least one location at a frequency of at least once every 10 years during the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. ~~Acceptance criteria will be revised to verify no unacceptable degradation.~~ ~~Enhance the Fire Water Program to test or replace sprinkler heads. If testing is chosen a representative sample of sprinkler heads will be tested before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the period of extended operation. Acceptance criteria will be no unacceptable degradation. NFPA-25 defines a representative sample of sprinklers to consist of a minimum of not less than 4 sprinklers or 1 percent of the number of sprinklers per individual sprinkler sample, whichever is greater. If replacement of the sprinkler heads is chosen, all sprinklers that have been in service for 50 years will be replaced.~~ Enhance the Fire Water Program to include periodic visual inspection of spray and sprinkler system internals for evidence of degradation. ~~Acceptance criteria will be enhanced to verify no unacceptable degradation.~~ <u>Revise Fire Water System Program procedures to inspect the strainers upstream of the deluge valves every three years.</u> <u>Revise Fire Water System Program procedures for flow testing, main drain testing, or internal inspection to specify an acceptance criterion of no debris observed (i.e., no corrosion products that are sufficient to obstruct flow or cause downstream components to become clogged).</u> <u>Revise Fire Water System Program procedures to specify that any sprinkler that shows signs of leakage or corrosion will be replaced.</u> <u>Revise Fire Water System Program procedures to require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the Corrective Action Program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains</u>			~~GNRO-2012-00064~~ <u>GNRO-2014/00030</u>

	and branch lines, and the performance of a complete flushing program by qualified personnel. Revise Fire Water System Program procedures to require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access.			
35	Revise Service Water Integrity Program documents to include inspections for loss of material due to erosion. Revise Service Water Integrity Program documents to include visual inspections for loss of coating Integrity during the 10-year period prior to the period of extended operation. Include provisions to specify subsequent coating inspections based on inspection results as follows. i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train need not be inspected during that inspection interval. ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval. Coating inspections will cover all accessible internal coated surfaces of applicable tanks.	B.1.41	Prior to May 1, 2024	GNRO-2013/00096 GNRO-2014/00030

	Visually inspect 50 percent of coated internal surfaces of piping or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations for coated piping will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance. Revise Service Water Integrity Program procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants," and that subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." Revise Service Water Integrity Program procedures to ensure an individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection. Revise the Service Water Integrity Program documents to include the following loss of coating integrity acceptance criteria (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. In the event peeling, delamination, cracking, or loss of adhesion is identified follow-up evaluations such as knife adhesion test, or adhesion test will be performed. In the event the base metal is exposed and the visual inspection identifies accelerated corrosion a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its intended function until the next projected inspection.			GNRO-2014/00030

Revisions to LRA Table B-3 are provided below with additions underlined and deletions marked through.

Table B-3

GGNS Program Consistency with NUREG-1801

Program Name	Plant Specific	NUREG-1801 Comparison		
		Consistent with NUREG-1801	Programs with Enhancements	Programs with Exceptions to NUREG-1801
Fire Water System		~~X~~	X	X
Service Water Integrity		X	X	

Revisions to LRA Section B.1.2 are provided below with additions underlined and deletions marked through.

B.1.2 ABOVEGROUND METALLIC TANKS

Program Description

The Aboveground Metallic Tanks Program is a new program that ~~will~~ manages loss of material and cracking of~~for~~ the ~~outer~~outside and inside surfaces of aboveground tanks constructed on concrete or soil.~~, including the bottom surfaces, of above-ground metallic tanks constructed on concrete or soil, using periodic visual inspections, measurements of the thickness of the tank bottoms, and preventive measures such as protective coatings and sealants. Tanks are inspected externally at least once every refueling cycle. In addition, ultrasonic testing (UT) thickness measurements of the tank bottoms will be performed at least once within the 5 years prior to the period of extended operation and whenever the tanks are drained during the period of extended operation.~~All outdoor tanks (except fire water storage tanks) and certain indoor tanks are included. If the tank exterior is fully visible, the tank's outside surfaces may be inspected under the program for inspection of external surfaces (ref section B.1.18) for visual inspections recommended in this AMP; surface examinations are conducted in accordance with the recommendations of this AMP. This program credits the standard industry practice of coating or painting the external surfaces of steel tanks as a preventive measure to mitigate corrosion. The program relies on periodic inspections to monitor degradation of the protective paint or coating. Tank inside surfaces are inspected by visual or surface examinations as required to detect applicable aging effects.

For storage tanks supported on earthen or concrete foundations, corrosion may occur at inaccessible locations, such as the tank bottom. Accordingly, verification of the effectiveness of the program is performed to ensure that significant degradation in inaccessible locations is not occurring and that the component's intended function is maintained during the period of extended operation. An acceptable verification program consists of thickness measurements of the tank bottom surface, as described in section A.1.2.

This program will be implemented prior to the period of extended operation.

NUREG-1801 Consistency

The Aboveground Metallic Tanks Program will be consistent with the program described in NUREG-1801, Section XI.M29, Aboveground Metallic Tanks, as modified by LR-ISG-2012-02.

Exceptions to NUREG-1801

None

Enhancements

None

Operating Experience

The Aboveground Metallic Tanks Program is a new program. Industry operating experience was considered in the development of this program. Plant operating experience will be gained as the program is implemented and will be factored into the program via the confirmation and corrective action elements of the GGNS 10 CFR 50 Appendix B quality assurance program.

The visual inspection and thickness measurement methods used in this program to detect aging effects are proven industry techniques that have been effectively used at GGNS in other programs. Visual inspections of the condensate storage tank ~~and fire water storage tanks~~ in 2007~~, 2008, and 2009~~ found no indications of age related degradation ~~which were resolved prior to any loss of intended function~~. As such, operating experience assures that implementation of the Aboveground Metallic Tanks Program will manage the effects of aging such that applicable components will continue to perform their intended functions consistent with the current licensing basis for the period of extended operation.

The process for review of future plant-specific and industry operating experience for this program is discussed in Section B.0.4.

Conclusion

The Aboveground Metallic Tanks Program will be effective for managing aging effects since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Aboveground Metallic Tanks Program provides assurance that 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.

Revisions to LRA Section B.1.18 are provided below with additions underlined and deletions marked through.

B.1.18 EXTERNAL SURFACES MONITORING

Program Description

The External Surfaces Monitoring Program is an existing program that manages aging effects through visual inspection of external surfaces for evidence of loss of material, cracking and change in material properties. Physical manipulation to detect hardening or loss of strength for elastomers and polymers is also used.

For a representative sample of indoor insulated components operated below the dew point, insulation is removed for inspection of the component surface. These inspections will be conducted during each 10 year period during the PEO. There are no in-scope outdoor insulated mechanical components.

NUREG-1801 Consistency

The External Surfaces Monitoring Program, with enhancements, will be consistent with the program described in NUREG-1801, Section XI.M36, External Surfaces Monitoring of Mechanical Components, as modified by LR-ISG-2012-02.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation

Element Affected	Enhancement
3. Parameters Monitored or Inspected 4. Detection of Aging Effects 5. Monitoring	The External Surfaces Monitoring Program will be enhanced to include instructions for monitoring aging effects for flexible polymeric components through manual or physical manipulation of the material, with a sample size for manipulation of at least 10 percent of available surface area.
4. Detection of Aging Effects	The External Surfaces Monitoring Program will be enhanced as follows. 1. Underground components within the scope of this program will be clearly identified in program documents. Underground components are those for which access is physically restricted. 2. Instructions will be provided for inspecting all underground components within the scope of this program during each five-year period, beginning ten years prior to the entry into the period of

	extended operation.
4. Detection of Aging Effects	Revise External Surfaces Monitoring Program procedures to specify the following for insulated components. • Periodic representative inspections will be conducted during each 10-year period during the PEO. • For a representative sample of insulated indoor components exposed to condensation (because the component is operated below the dew point), insulation will be removed for visual inspection of the component surface. Inspections will include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum), or for components with a configuration which does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, insulation will be removed and a minimum of 25 inspections will be performed that can be a combination of 1-foot axial length sections and individual components for each material type. • Inspection locations will be selected based on the likelihood of corrosion under insulation (CUI). For example, CUI is more likely for components experiencing alternate wetting and drying in environments where trace contaminants could be present and for components that operate for longer periods of time below the dew point. Subsequent inspections can be limited to an examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation, if the following conditions are verified in the initial inspection. ➢ No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction, and ➢ No evidence of cracking If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), periodic inspections under the insulation will continue as described above. • Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Tightly adhering insulation is

	<u>considered a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope accessible piping component surfaces that have tightly adhering insulation will be visually inspected for damage to the moisture barrier at the same frequency as inspections of other types of insulation. These inspections will not be credited towards the inspection quantities for other types of insulation.</u>

Revisions to LRA Section B.1.21 are provided below with additions underlined and deletions marked through.

B.1.21 FIRE WATER SYSTEM

Program Description

The Fire Water System Program is an existing program that manages loss of material and fouling for components in fire protection systems using preventive, inspection, and monitoring activities, including periodic full-flow flush tests, system performance testing and testing or replacement of sprinkler heads. Applicable industry standards and guidance documents, including NFPA codes, are used to delineate the program. The program includes acceptance criteria for the water-based fire protection system to maintain required pressure, and acceptance criteria will be enhanced to verify no unacceptable degradation. Corrective action is initiated upon loss of system operating pressure, which is monitored continuously.

NUREG-1801 Consistency

The Fire Water System Program, with enhancements, is consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, as modified by LR-ISG-2012-02, with exceptions as noted.

Exceptions to NUREG-1801

~~None~~ The Fire Water System Program, with enhancements, is consistent with the program described in NUREG-1801, Section XI.M27, Fire Water System, as modified by LR-ISG-2012-02, with exceptions as noted.

Elements Affected	Exceptions
4. Detection of Aging Effects	1. NFPA 25, Section 5.2.1 specifies annual sprinkler inspections. GGNS performs sprinkler inspections on a 24-month interval. 2. NFPA 25, Section 5.2.1.1 specifies inspections for sprinkler orientation, foreign material, physical damage and loading due to dust or debris. The effects of aging are not causes of discrepancies involving sprinkler orientation, foreign material, physical damage and loading due to dust or debris. Therefore, inspections for these conditions are not included in the aging management programs for the GGNS fire water system. 3. NFPA 25, Section 6.3.1 specifies flow testing every five years at the hydraulically most remote hose connections of each zone of an automatic standpipe system to verify the water supply still provides the design pressure at the required flow. GGNS does not perform this flow testing. 4. NFPA 25, Sections 6.3.1.5 and 13.2.5 specifies main drain testing on all standpipes and risers in the water-based fire suppression system with automatic water supplies to determine if there has been a change in the water supply

	piping and control valves. GGNS does not perform main drain testing on all standpipes and risers; however, GGNS does perform more than 30 main drain tests throughout the plant associated with in-scope standpipes and risers to verify there has not been a change in the water supply piping and control valves. For example, GGNS performs six main drain tests in the auxiliary building, ten in the turbine building, two in the control building, and three in the EDG building. 5. NFPA 25, Section 6.3.1.5.2, which refers to Section 5.3.2, addresses the calibration of gauges used during flow testing. The calibration of gauges is part of ongoing plant operations and is not part of the GGNS Fire Water System Program. 6. During an inspection in accordance with NFPA 25 Section 9.2.6.4, NFPA 25 Section 9.2.7.1 specifies an evaluation of interior tank coatings in accordance with the adhesion test of ASTM D 3359, Standard Test Methods for Measuring Adhesion by Tape Test, generally referred to as the "cross-hatch test." When indications are identified in the fire water tank coating, GGNS performs holiday testing. In addition, GGNS performs ultrasonic thickness checks or mechanical measurements of any identified corroded areas. GGNS does not apply the cross-hatch test. 7. NFPA 25, Section 13.4.3.2.2 specifies full flow trip testing to ensure no flow blockage downstream of deluge valves. GGNS performs full flow deluge valve testing for the deluge systems associated with the transformers. The deluge valves associated with the charcoal filters, the turbine building hydrogen seal oil and recirculation feed pump turbine (RFPT) lube oil reservoir are not full flow tested at GGNS.

Exception Notes:

1. Access for some inspections is feasible only during refueling outages, which occur once every 24 months. Inspection once every 24 months has been effective at maintaining component intended functions.

2. GGNS addresses the identified conditions during design, installation and operation of the fire water system rather than in an aging management program because they are not issues attributable to the effects of aging.

3. To flow test the hydraulically most remote hose connection of the automatic standpipe system in a manner that would provide sufficient information to verify design pressure and flow would generate a large quantity of liquid that is potentially radwaste and could create a risk of wetting components critical to normal and shutdown operations. By not performing additional flow testing, the potential for creating radwaste and increasing operational risk is reduced.

   GGNS performs main header flow testing in seven loops that supply the standpipe system to verify the water supply provides the design pressure and required flow. GGNS tests the fire water hose stations listed in the Technical Requirements Manual (TRM) every three years, performs a version of a main drain test in each building annually on a portion of the deluge and sprinkler systems, and verifies the fire water system valve line-up monthly per the TRM. During the fire water hose station tests, GGNS flows 2 to 3 gallons of fire water into a pail to ensure there is no blockage. The station tests approximately 43 fire water hose stations in the auxiliary building, 16 fire water hose stations in the containment building, 2 fire water hose stations in the EDG building, and 13 fire water hose stations in the control building. Acceptance criteria for the open flow paths consist of (1) verifying valve operability and (2) flow through valve and connection shall be verified and there shall be no indication of obstruction or other undue restriction of water flow.

   In addition, Section 6.3.1 has been revised in the 2014 edition of NFPA 25 to indicate this testing provision is only applicable to Class I and Class III standpipe systems. The automatic standpipe system at GGNS is a Class II standpipe system.

4. The basis for GGNS taking an exception to performing main drain tests on all standpipes and risers is (1) the turbine building standpipes and risers are only in scope for (a)(2) and therefore, main drain testing is not necessary to demonstrate performance of the license renewal intended function, and (2) main drain testing in radiologically controlled areas and areas that contain equipment critical for normal and shutdown operations creates additional liquid radwaste and increases operational risk.

5. Gauges are active components. Therefore, gauges are not subject to aging management review for license renewal and their calibration is not included in the aging management program.

6. Cross hatch testing is a destructive test that could potentially lead to exceeding the 7-day limiting condition for operation for the fire system water supply. In the event the 7-day limiting condition for operation is exceeded, GGNS is required to align an alternate water supply to the fire water system, which may be more aggressive to system components than the normal water supply.

7. The deluge valves associated with the auxiliary building standby charcoal filters, containment cooling system charcoal filters, containment vent charcoal filter, RFPT lube oil reservoir, turbine building hydrogen seal oil, and control room fresh air charcoal filters are not trip tested at full flow. The turbine building hydrogen seal oil and RFPT LO reservoir deluge valves are only in scope for (a)(2) and are not required to meet the testing requirements of LR-ISG-2012-02. The deluge valves associated with the control room fresh air charcoal filters are trip tested, but not at full flow. The deluge systems associated with the auxiliary building standby, containment cooling system, and containment vent charcoal filters have manually actuated deluge valves. Upon the detection of heat there is an alarm in the control room. Operating personnel must confirm the presence of a fire before manually opening the isolation valve and tripping the deluge valve for these charcoal filters. The deluge vales are not trip tested due to the potential for water damaging the charcoal in the filter units. The piping downstream of manual deluge trip valves is dry and the deluge nozzles are within the filter housing and not easily accessible. Since the nozzles in the charcoal filters are enclosed, it is unlikely the orientation would change due to bumping or that bugs would build nests that could threaten performance of the spray nozzles. Nozzles are inspected when charcoal is replaced in the filters. (See enhancement to perform inspection of the nozzles when the charcoal is replaced.)

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Elements Affected	Enhancements
3. Parameters Monitored or Inspected ~~6. Acceptance Criteria~~	The Fire Water System Program will be enhanced to include periodic visual inspection of spray and sprinkler system internals for evidence of degradation. ~~Acceptance criteria will be enhanced to verify no unacceptable degradation.~~
3. Parameters Monitored or Inspected	Revise Fire Water System Program procedures to include inspecting sprinklers in the overhead from the floor for signs of corrosion.
4. Detection of Aging Effects ~~6. Acceptance Criteria~~	Revise the Fire Water System Program procedure ~~will be enhanced~~ to include periodic inspection of hose reels for degradation. ~~Acceptance criteria will be enhanced to verify no unacceptable degradation~~.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to replace sprinklers that the tested sprinkler represents, if the tested sprinkler fails to meet the test acceptance criteria.
4. Detection of Aging Effects	Revise Fire Water System Program procedures to ensure the hydrant valve is opened fully and ensure the hydrant flows for not less than one minute during flow testing.
4. Detection of Aging Effects	Revise Fire Water System Program procedures for inspecting the interior of the fire water tanks to include the following. • testing for possible voids beneath the tank • inspection of the vortex breaker • testing required by Section 9.2.7 of NFPA-25 (2011 Edition) if a coating defect is identified ➢ take dry film thickness measurements at random locations to determine the overall coating thickness when specified by NFPA-25 (2011 Edition) Section 9.2.6.4 ➢ perform a spot wet-sponge test to detect pinholes, cracks, or other compromises in the coating when required by NFPA-25 (2011 Edition) Section 9.2.6.4 ➢ take nondestructive ultrasonic readings to evaluate the wall thickness where there is evidence of pitting or corrosion as specified in NFPA-25 (2011 Edition) Section 9.2.6.4 ➢ testing the tank bottom for metal loss or rust on the underside by use of ultrasonic testing where there is evidence of pitting or corrosion as specified by NFPA-25 (2011 Edition) Section 9.2.6.4
4. Detection of Aging Effects	Revise Fire Water System Program procedures to ensure there is no flow blockage by visually inspecting the charcoal filter deluge nozzles when the charcoal is replaced.

Elements Affected	Enhancements
~~4. Detection of Aging Effects~~	~~The Fire Water System Program will be enhanced to include one of the following options.~~ ~~(1) Wall thickness evaluations of fire protection piping using non-intrusive techniques (e.g., volumetric testing) to identify evidence of loss of material will be performed prior to the period of extended operation and periodically thereafter. 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.~~ ~~OR~~ ~~(2) A visual inspection of the internal surface of fire protection piping will be performed upon each entry to the system for routine or corrective maintenance. These inspections will be capable of evaluating (a) wall thickness to ensure against catastrophic failure and (b) the inner diameter of the piping as it applies to the design flow of the fire protection system. Maintenance history shall be used to demonstrate that such inspections have been performed on a representative number of locations prior to the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. Additional inspections will performed as needed to obtain this representative sample prior to the period of extended operation. The periodicity of inspections during the period of extended operation will be determined through an engineering evaluation of the operating experience gained from the results of previous inspections of fire water piping.~~
4. Detection of Aging Effects	Revise Fire Water System Program procedures to periodically open a flushing connection at the end of one main and remove a component such as a sprinkler toward the end of one branch line five years prior to the PEO, and every five years during the PEO to perform a visual inspection in accordance with NFPA 25 (2011 Edition) Section 14.2.1.
4. Detection of Aging Effects ~~6. Acceptance Criteria~~	The Fire Water System Program will be enhanced to include a visual inspection of a representative number of locations on the interior surface of below grade fire protection piping at a frequency of at least once every ten years during the period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. ~~Acceptance criteria will be no unacceptable degradation.~~
4. Detection of Aging Effects	Revise Fire Water System Program procedures to ensure sprinkler heads are tested or replaced in accordance with NFPA--25 (2011 Edition), Section 5.3.1. ~~The Fire Water System Program will be enhanced to include testing or~~

Elements Affected	Enhancements
	~~replacement of sprinkler heads. If testing is chosen a representative sample of sprinkler heads will be tested before the end of the 50-year sprinkler head service life and at 10-year intervals thereafter during the extended period of operation. NFPA-25 defines a representative sample of sprinklers to consist of a minimum of not less than 4 sprinklers or 1 percent of the number of sprinklers per individual sprinkler sample, whichever is greater. If replacement of the sprinkler heads is chosen, all sprinklers that have been in service for 50 years will be replaced.~~
4. Detection of Aging Effects	Revise Fire Water System Program procedures to inspect the strainers upstream of the deluge valves every three years.
6. Acceptance Criteria	Revise Fire Water System Program procedures for flow testing, main drain testing, or internal inspection to specify an acceptance criterion of no debris observed (i.e., no corrosion products that are sufficient to obstruct flow or cause downstream components to become clogged).
7. Corrective Action	Revise Fire Water System Program procedures to specify that any sprinkler that shows signs of leakage or corrosion will be replaced.
7. Corrective Action	Revise Fire Water System Program procedures to require an obstruction evaluation if any signs of abnormal corrosion or blockage are identified during flow testing, main drain testing, or internal inspection. Any signs of corrosion or blockage should be removed, its source determined and corrected, and the condition entered into the Corrective Action Program. Where corrosion or blockage is found, the obstruction evaluation should consider system valves, risers, cross mains and branch lines, and the performance of a complete flushing program by qualified personnel.
7. Corrective Action	Revise Fire Water System Program procedures to require an obstruction evaluation in the event there is frequent false tripping of the dry pipe fire suppression system associated with the auxiliary building railroad access.

Revisions to LRA Section B.1.26 are provided below with additions underlined.

B.1.26 INTERNAL SURFACES IN MISCELLANEOUS PIPING AND DUCTING COMPONENTS

Program Description

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program that manages the effects of aging using opportunistic visual inspections of the internal surfaces of piping and components during periodic surveillances or maintenance activities when the surfaces are accessible for visual inspection.

To ensure a representative number of components are inspected, in each 10-year period during the period of extended operation (PEO), an assessment will be made of the opportunistic inspections completed during that period for each material-environment-aging effect combination within the scope of this program. Directed inspections will be conducted to ensure that an inspection sample size of 20 percent, with a maximum sample size of 25 inspections, is completed for each material-environment-aging effect combinations during the 10-year period under review. Where practical, inspections shall be conducted at locations that are most susceptible to the effects of aging because of time in service, severity of operating conditions (e.g., low or stagnant flow), and lowest design margin. An inspection conducted of a material in a more severe environment may be credited as an inspection of the same material in a less severe environment.

For metallic components visual inspection will be used to detect loss of material and fouling. For elastomeric components, visual inspections will be used to detect cracking and change in material properties. The program monitors surface condition for visible evidence of loss of material in metallic components and changes in material properties for elastomeric components, including possible evidence of surface discontinuities. Visual examinations of elastomeric components are accompanied by physical manipulation or pressurization (i.e., the component is sufficiently pressurized to expand the surface of the material in such a way that cracks or crazing are evident) such that changes in material properties are readily observable.

NUREG-1801 Consistency

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program is consistent with the program described in NUREG-1801, Section XI.M38, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, as modified by LR-ISG-2012-02.

Revisions to LRA Section B.1.35 are provided below with additions underlined.

B.1.35 PERIODIC SURVEILLANCE AND PREVENTIVE MAINTENANCE

Program Description

There is no corresponding NUREG-1801 program.

The Periodic Surveillance and Preventive Maintenance Program is an existing program that manages aging effects not managed by other aging management programs, including loss of material due to erosion, <u>loss of coating integrity</u>, cracking, and change in material properties.

Credit for program activities has been taken in the aging management review of the following systems and structures.

Containment Building	Visually inspect and manually flex the rubber gasket/seal for upper containment pool gates to verify the absence of cracks and significant change in material properties.
Low pressure core spray system (LPCS)	Use visual or other NDE techniques to inspect external surface of LPCS piping passing through the waterline region of suppression pool to manage loss of material.
Residual heat removal (RHR) system	Use visual or other NDE techniques to inspect external surface of RHR piping passing through the waterline region of suppression pool to manage loss of material.
Pressure relief system	Use visual or other NDE techniques to inspect external surface of pressure relief system piping passing through the waterline region of the suppression pool to manage loss of material.
Reactor core isolation cooling (RCIC) system	Use visual or other NDE techniques to inspect external surfaces of RCIC system piping passing through the waterline region of the suppression pool to manage loss of material.
Nonsafety-related systems affecting safety-related systems	Visually inspect the internal surfaces of a representative sample of piping in the control rod drive (CRD) system to manage loss of material. Visually inspect the internal surfaces of a representative sample of piping and valve bodies in the circulating water system (N71) to manage loss of material. Visually inspect the internal surfaces of a representative sample of piping and valve bodies in the floor and equipment drain system (P45) to manage loss of material. Use visual or other NDE techniques to inspect the internal surfaces of the piping adjacent to the high pressure, intermediate pressure, and low pressure condenser shells in the circulating water system (N71) to manage loss of material due to erosion. Use visual or other NDE techniques to inspect the internal surfaces of the moisture separator-reheater in the moisture separator-reheater vents and drains system (N35) to manage loss of material due to erosion.
High pressure core spray (HPCS) system	Use visual or other NDE techniques to inspect HPCS piping passing through the waterline region of the suppression pool to manage loss of material.

Floor and equipment drain system	Use visual or other NDE techniques to inspect piping below the waterline in the in-scope sumps to manage loss of material. Visually inspect the internal surfaces of a representative sample of piping, drain housings, and valve bodies in the floor and equipment drain system (P45) to manage loss of material.
Circulating water system Standby service water system Component cooling water system Plant service water system Fire protection system	Perform wall thickness measurements using UT or other suitable techniques at selected locations to identify loss of material due to microbiologically Influenced corrosion (MIC) in piping components of these systems that are included in the scope of license renewal. Select inspection locations based on pipe configuration, flow conditions and operating history to represent a cross-section of potential MIC sites. Periodically review the selected locations to validate their relevance and usefulness, and modify accordingly. Compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation. Compare wall thickness measurements to code minimum wall thickness plus margin for corrosion during the refueling cycle (T_{marg}) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements as needed for each selected location based on the rate of corrosion and expected time to reach T_{marg}. Perform a minimum of five MIC degradation inspections per refueling cycle until MIC no longer meets the criteria for recurring internal corrosion. Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations.
Internally Coated Components	
Fire protection system	Visually inspect internal coated surfaces of piping and tanks to manage loss of coating integrity.
Reactor water cleanup system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
CRD maintenance facility, flush tank filter and leak test	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Condensate and feedwater system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Condensate cleanup system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Component cooling water system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Turbine building cooling water	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Domestic water system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.

Plant chilled water system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Drywell chilled water system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Standby diesel generator system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
HPCS diesel generator system	Visually inspect internal coated tank surfaces to manage loss of coating integrity.
Combustible gas control system	Visually inspect internal coated heat exchanger surfaces to manage loss of coating integrity.
Drywell chilled water system	Visually inspect internal coated heat exchanger surfaces to manage loss of coating integrity.
Control room HVAC system	Visually inspect internal coated heat exchanger surfaces to manage loss of coating integrity.

Evaluation

1. Scope of Program

The Periodic Surveillance and Preventive Maintenance Program, with regard to license renewal, includes the specific structures and components identified in the aging management reviews as listed in the table above.

2. Preventive Actions

Similar to other condition monitoring programs described in NUREG-1801, the Periodic Surveillance and Preventive Maintenance Program does not include preventive actions.

3. Parameters Monitored/Inspected

The GGNS Periodic Surveillance and Preventive Maintenance Program

a) monitors cracking and change in material properties for elastomeric components, and

b) monitors the surface condition of internal and external surfaces of components to manage loss of material

c) monitors the wall thickness of piping components to manage loss of material due to recurring internal corrosion.

d) monitors the condition of internal coated surfaces of components to manage loss of coating integrity

4. Detection of Aging Effects

Preventive maintenance activities and periodic surveillances provide for periodic component inspections to detect aging effects and loss of coating integrity. Inspection intervals are established such that they provide timely detection of degradation prior to loss of intended functions. Inspection intervals, sample sizes, and data collection methods are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations.

Established techniques such as visual inspections are used. Each inspection occurs at least once every five years with the exception of coating inspections for which frequency is based on coating condition. The selection of components to be inspected will focus on locations which are most susceptible to aging, where practical. Established inspection methods to detect aging effects include: 1) visual inspections and manual flexing of elastomer components and 2) visual inspections or other NDE techniques for metallic components. Inspections are performed by personnel qualified to perform the inspections.

For each activity that refers to a representative sample, a representative sample is 20% of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components.

During the10-year period prior to the period of extended operation, visual inspections will be performed of coated internal surfaces. Subsequent coating inspections will be performed based on inspection results as follows.

i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train need not be inspected during that inspection interval.
ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every other refueling outage interval.

Coating inspections will cover all accessible internal coated surfaces of applicable tanks and heat exchangers. For internal coatings of piping, inspections will cover 50 percent of coated piping within the system or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations of coated piping will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance.

Individuals performing coating inspections are certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants. Evaluators of inspection findings are nuclear coatings subject matter experts qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." An individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating degradation including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to a subsequent inspection or repair opportunity.

5. Monitoring and Trending

Preventive maintenance activities provide for monitoring and trending of aging degradation. Inspection intervals are established such that they provide for timely detection of component degradation. Inspection intervals are dependent on component material and environment and take into consideration industry and plant-specific operating experience and manufacturers' recommendations. Prerequisites for coating inspections include review of the results of previous inspections.

6. Acceptance Criteria

Periodic Surveillance and Preventive Maintenance Program acceptance criteria are defined in specific inspection procedures. The procedures confirm that the structure or component intended function(s) are maintained by verifying the absence of aging effects or by comparing applicable parameters to limits established by plant design basis.

Acceptance criteria include 1) for elastomer components. no significant change in material properties or cracking while visually observing and flexing components. and 2) for metallic components. no unacceptable loss of material such that component wall thickness remains above the required minimum.

Loss of coating integrity acceptance criteria are (1) peeling and delamination are not acceptable, (2) cracking is not acceptance if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. In the event peeling, delamination, cracking, or loss of adhesion is identified follow-up evaluations such as knife adhesion test, or adhesion test will be performed. In the event the base metal is exposed and the visual inspection identifies corrosion, a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its intended function until the next inspection or repair opportunity.

7. Corrective Actions

Corrective actions, including root cause determination and prevention of recurrence, are implemented in accordance with requirements of 10 CFR Part 50, Appendix B.

8. Confirmation Process

This element is discussed in Section B.0.3.

9. Administrative Controls

This element is discussed in Section B.0.3.

10. Operating Experience

Typical inspection results of this program include the following.

NDE measurements were made on Division II diesel generator exhaust piping in 2005 to check wall thickness. Analysis of the data showed acceptable results. There was no other indication of aging such as erosion or corrosion. Preventive maintenance test results confirming the absence of significant wall loss provides evidence that the program is effective for managing loss of material.

In 2006, visual inspection of the internal surfaces of a check valve in the component cooling water system found significant wear. The affected parts were replaced and the valve was returned to service. There was no other indication of aging such as erosion or corrosion. Identification of signs of possible degradation and corrective action prior to loss of intended function provides evidence that the program is effective for managing aging effects for components.

The process for review of future plant-specific and industry operating experience for this program is discussed in Section B.0.4.

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Elements Affected	Enhancements
1. Scope of Program 3. Parameters Monitored or Inspected 4. Detection of Aging Effects 6. Acceptance Criteria	The Periodic Surveillance and Preventive Maintenance Program will be enhanced to revise program guidance documents as necessary to include all activities described in the table provided in the program description.

Conclusion

The Periodic Surveillance and Preventive Maintenance Program has been effective at managing aging effects. The Periodic Surveillance and Preventive Maintenance Program assures the effects of aging are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Revisions to LRA Section B.1.41 are provided below with additions underlined.

B.1.41 SERVICE WATER INTEGRITY

Program Description

The Service Water Integrity Program is an existing program that manages loss of material and fouling in open-cycle cooling water systems as described in the GGNS response to NRC GL 89-13. The program also includes inspections for loss of material due to erosion and loss of coating integrity. In addition, the program includes inspections of coatings for submerged piping in the standby service water (SSW) basin. The frequency of these inspections is based on the inspection results.

NUREG-1801 Consistency

The Service Water Integrity Program, with enhancement, is consistent with the program described in NUREG-1801, Section XI.M20, Open-Cycle Cooling Water System. Additional activities are included to manage loss of coating integrity for components with internal coatings.

Exceptions to NUREG-1801

None

Enhancements

The following enhancements will be implemented prior to the period of extended operation.

Elements Affected	Enhancement
4. Detection of Aging Effects	Revise Service Water Integrity Program documents to include inspections for loss of material due to erosion.
4. Detection of Aging Effects	Revise Service Water Integrity Program documents to include visual inspections for loss of coating Integrity during the 10-year period prior to the period of extended operation. Include provisions to specify subsequent coating inspections based on inspection results as follows. i. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections will be performed at least once every 6 years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train need not be inspected during that inspection interval. ii. If the inspection results do not meet (i), yet a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted on an every

	other refueling outage interval. Coating inspections will cover all accessible internal coated surfaces of applicable tanks. Visually inspect 50 percent of coated internal surfaces of piping or a minimum of 73 locations of 360 degrees of one linear foot for each combination of type of coating, material the coating is protecting, and environment. Inspection locations for coated piping will be based on coating degradation susceptibility, operating experience, vendor recommendation and safety significance. Revise Service Water Integrity Program procedures to ensure coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants," and that subsequent evaluation of inspection findings is conducted by a nuclear coatings subject matter expert qualified in accordance with ASTM D 7108-05, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist." Revise Service Water Integrity Program procedures to ensure an individual knowledgeable and experienced in nuclear coatings work will prepare a coating report that includes a list of locations identified with coating deterioration including, where possible, photographs indexed to inspection location, and a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where coating repair can be postponed to the next inspection.
6. Acceptance Criteria	Revise the Service Water Integrity Program documents to include the following loss of coating integrity acceptance criteria (1) peeling and delamination are not acceptable, (2) cracking is not acceptable if accompanied by delamination or loss of adhesion, and (3) blisters are limited to intact blisters that are completely surrounded by sound coating bonded to the surface. In the event peeling, delamination, cracking, or loss of adhesion is identified follow-up evaluations such as knife adhesion test, or adhesion test will be performed. In the event the base metal is exposed and the visual inspection identifies accelerated corrosion a volumetric examination will be performed to ensure there is sufficient wall thickness so that the component can perform its intended function until the next projected inspection.

Operating Experience

A snapshot program self-assessment in 2002 concluded that the standby service water (SSW) system meets its design and licensing bases and that it is capable of performing its safety functions.

Results of a QA audit in 2003 indicated that the service water integrity program was effective in meeting regulatory requirements and applicable codes and standards.

A program assessment in 2003 identified degraded areas of coating based on inspections of submerged piping in SSW basins. A corrective action plan was initiated and completed to address this issue. Identification of degradation and corrective action prior to loss of intended function provide evidence that the program is effective for managing aging effects.

In 2004 a strategic plan was established to define monitoring practices and establish a chemical treatment program for the continued improvement in the performance of the SSW system. The plan includes controls for biological fouling, scale formation, solids deposition, and metal corrosion inhibition. Identification of program deficiencies, and subsequent corrective actions, provide assurance that the program will remain effective for managing loss of material of components.

A QA audit in 2007 focused on reviewing responses and action plans to address program issues that had been identified by NRC and by an Entergy corporate assessment the previous year. Corrective action plans were reviewed and found to contain well-documented causes with timely action plans. This audit confirmed that the service water integrity program was being implemented in a manner that resulted in effective monitoring, inspection, and detection of degradation.

A program assessment in 2009 evaluated the health of the system and the program, corrective action resolution and timeliness, preventive maintenance backlog, leaks and leak repairs, trending and monitoring practices, long-range plans, and operating experience reviews. The report concluded that performance and regulatory margin of the SSW system will be restored once appropriate corrective actions are implemented for certain structural and operational issues. Corrective actions were set forth to address these issues. The execution of aggressive preventive maintenance, inspections and effective chemical treatment assure the long-term integrity of the system.

A QA audit in 2009 confirmed that the service water integrity program was being implemented in a manner that resulted in effective monitoring, inspection, and detection of degradation.

During a visual inspection in 2010, excessive pitting and corrosion was detected on a standby service water valve body and discharge flange. Ultrasonic (UT) examination was performed, and UT data indicated the remaining wall thickness for the valve body was in excess of the minimum wall thicknesses required by ASME Code. Identification and evaluation of aging effects prior to loss of intended function provides evidence that the program remains effective.

The process for review of future plant-specific and industry operating experience for this program is discussed in Section B.0.4.

Conclusion

The Service Water Integrity Program has been effective at managing aging effects. The Service Water Integrity Program assures the effects of aging <u>and loss of coating integrity</u> are managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the period of extended operation.

Attachment 3 to

GNRO-2014/00030

Additional LRA Changes

During an internal review of project reports in support of the GGNS license renewal application, a discrepancy was noted between the tank material identified in the LRA and the actual tank material. GGNS LRA Table 3.3.2-19-20 included table entries for tanks constructed of carbon steel (material). All tanks subject to aging management review applicable to this table are constructed of stainless steel. LRA Table 3.3.2-19-20 is revised as shown below to correct the error and identify the aging management review results for the stainless steel tanks.

Section 3.4.2.1.2 and LRA Tables 3.3.2-19-7 and 3.4.2-2-14 are revised as shown below to include additional material changes identified during the extent of condition review for the discrepancy noted above. Deletions are shown with strikethrough and additions with underline.

Table 3.3.2-19-20: Floor and Equipment Drain System [10 CFR 54.4(a)(2)]

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	~~Carbon~~ Stainless steel	Air – indoor (ext)	~~Loss of material~~ None	~~External Surfaces Monitoring~~ None	~~VII.I.A-77~~ VII.J.AP-123	3.3.1-~~78~~120	~~A~~ C
Tank	Pressure boundary	~~Carbon~~ Stainless steel	Concrete (ext)	None	None	VII.J.AP-19	3.3.1-120	C
Tank	Pressure boundary	~~Carbon~~ Stainless steel	Waste water (int)	Loss of material	Internal Surfaces in Miscellaneous Piping and Ducting Components	VII.E5.AP-~~281~~ 278	3.3.1-~~91~~ 95	C

Table 3.3.2-19-7: Reactor Water Cleanup System [10 CFR 54.4(a)(2)]

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Stainless steel	Air – indoor (ext)	None	None	VII.J.AP-123	3.3.1-120	A
Tank	Pressure boundary	Stainless steel	Treated water (int)	Loss of material	Water Chemistry Control – BWR	VII.E3.AP-110	3.3.1-25	C, 301

Table 3.4.2-2-14: Generator Primary Water System, Nonsafety-Related Components Affecting Safety-Related Systems

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	~~Carbon steel~~ Stainless steel	Air – indoor (ext)	~~Loss of Material~~ None	~~External Surfaces Monitoring~~ None	~~VIII.H.S-29~~ VIII.I.SP-12	~~3.4.1-34~~ 3.4.1-58	A
Tank	Pressure boundary	~~Carbon steel~~ Stainless steel	Treated water (int)	Loss of material	Water Chemistry Control – Closed Treated Water Systems	~~VIII.E.S-23~~ VIII.E.SP-39	~~3.4.1-25~~ 3.4.1-26	C
Tank	Pressure boundary	Plastic	Air – indoor (ext)	Change in material properties	External Surfaces Monitoring	--	--	F
Tank	Pressure boundary	Plastic	Treated water (int)	Change in material properties	Internal Surfaces in Miscellaneous Piping and Ducting Components	--	--	F

3.4.2.1.2 Miscellaneous Steam and Power Conversion Systems in Scope for 10 CFR 54.4(a)(2)

The following lists encompass materials, environments, aging effects requiring management, and aging management programs for the series 3.4.2-2-xx tables.

Nonsafety-related components affecting safety-related systems are constructed of the following materials.

- carbon steel
- copper alloy
- copper alloy > 15% zinc or > 8% aluminum
- elastomer
- glass
- gray cast iron
- nickel alloy
- stainless steel
- plastic