Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402

CNL-13-105

November 4, 2013

10 CFR Part 54

ATTN: Document Control Desk
U.S. Nuclear Regulatory Commission
Washington, D.C. 20555-0001

Sequoyah Nuclear Plant, Units 1 and 2
Facility Operating License Nos. DPR-77 and DPR-79
NRC Docket Nos. 50-327 and 50-328

Subject: **Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 10 (3.0.3-1, Requests 3, 4, 6), 12 (B.1.6-1b, B.1.6-2b), 16 (4.3.1-8a) (TAC Nos. MF0481 and MF0482)**

References:

1. Letter to NRC, "Sequoyah Nuclear Plant, Units 1 and 2 License Renewal," dated January 7, 2013 (ADAMS Accession No. ML13024A004)
2. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 10," dated August 2, 2013 (ADAMS Accession No. ML13204A257)
3. Letter to NRC, "Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 10 (B.1.23-2a), 11 (4.1-8a), and 12 (30-day)," dated September 30, 2013 (ADAMS Accession No. ML13276A018)
4. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 16," dated October 18, 2013 (ADAMS Accession No. ML13282A330)

By letter dated January 7, 2013 (Reference 1), Tennessee Valley Authority (TVA) submitted an application to the Nuclear Regulatory Commission (NRC) to renew the operating licenses for the Sequoyah Nuclear Plant (SQN), Units 1 and 2. The request would extend the licenses for an additional 20 years beyond the current expiration date.

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By Reference 2, the NRC forwarded a request for additional information (RAI) labeled Set 10, which included RAI 3.0.3-1, Requests: 3, 4 and 6 with a required response due date no later than October 31, 2013. However, Mr. Richard Plasse, NRC Project Manager for the SQN License Renewal, has given a verbal extension for the response to November 4, 2013. Enclosure 1 provides the TVA responses.

In Reference 3, TVA submitted responses that included RAIs B.1.6-1a, and B.1.6-2a. In an October 23, 2013 telecom, Mr. Plasse requested clarifications to these RAI responses. Enclosure 1 provides the requested clarifications.

By Reference 4, the NRC forwarded an RAI labeled Set 16, which included RAI 4.3.1-8a with a required response due date no later than November 18, 2013. Enclosure 1 provides the TVA response.

Enclosure 2 is an updated list of the regulatory commitments for license renewal, which supersedes all previous versions.

Consistent with the standards set forth in 10 CFR 50.92(c), TVA has determined that the additional information, as provided in this letter, does not affect the no significant hazards considerations associated with the proposed application previously provided in Reference 1.

Please address any questions regarding this submittal to Henry Lee at (423) 843-4104.

I declare under penalty of perjury that the foregoing is true and correct. Executed on this 4th day of November 2013.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:
1. TVA Responses to NRC Request for Additional Information: Sets 10 (3.0.3-1, Requests 3, 4, 6), 12 (B.1.6-1b, B.1.6-2b), 16 (4.3.1-8a)
2. Regulatory Commitment List, Revision 11

cc (Enclosures):
NRC Regional Administrator – Region II
NRC Senior Resident Inspector – Sequoyah Nuclear Plant

ENCLOSURE 1

Tennessee Valley Authority
Sequoyah Nuclear Plant, Units 1 and 2 License Renewal
TVA Responses to NRC Request for Additional Information:
Sets 10 (3.0.3-1, Requests 3, 4, 6), 12 (B.1.6-1b, B.1.6-2b), 16 (4.3.1-8a)

Set 10: RAI 3.0.3-1, Request 3

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 this OE.

These issues are related to the following, as described in detail below:

3. Loss of coating integrity for Service Level III and other coatings.

Issue:

3. Loss of coating integrity for Service Level III and Other coatings

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, would be managed for Service Level III and other coatings.

For purposes of this RAI:

a. 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).
b. "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).
c. The term "coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfaces that are designed to adhere to a component to protect its surface.
d. The terms "paint" and "linings" should be considered as coatings.

The staff does not consider a coating to be a component. A coating becomes an integral part of an in-scope component, providing it protection from corrosion, just as the addition of chromium to steel mitigates corrosion. Just as stainless steel introduces a new aging effect, cracking due to stress corrosion cracking (SCC), to which carbon steel is generally not susceptible, the addition of a coating to a component introduces the potential for unanticipated or accelerated corrosion of the base metal and degraded performance of downstream equipment due to flow blockage. If coatings are installed, loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage must be managed regardless of whether the coatings are credited for aging.

Request:

3. Loss of coating integrity for Service Level III and Other coatings

a. *State whether any in-scope components have internal Service Level III or Other coatings.*

b. *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:*
   i. *For each installed coating application, whether installation records, if available, used to apply the coating included material manufacturer installation specifications.*
   ii. *The inspection method.*
   iii. *The parameters to be inspected.*
   iv. *When inspections will commence and the frequency of subsequent inspections. Consider such factors as whether coatings can be verified to have been installed to manufacturer specifications, prior inspection findings of acceptable or degraded coatings, and coating replacement history.*
   v. *The extent of inspections and the basis for the extent of inspections if it is not 100 percent.*
   vi. *The training and qualification of individuals involved in coating inspections.*
   vii. *How trending of coating degradation will be conducted.*
   viii. *Acceptance criteria.*
   ix. *Corrective actions for coatings that do not meet acceptance criteria.*
   x. *The program(s) that will be augmented to include the above requirements.*

c. *State how LRA Section 3 Table 2s, Appendix A, and Appendix B will be revised to address the program used to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage.*

TVA Response to RAI 3.0.3-1, Request 3, Loss of Coating Integrity

During the individual plant assessment, applicable aging effects were considered for license renewal in-scope components regardless of whether preventive programs such as coating or water chemistry programs were applied.

The following components have the potential for degradation of coatings to affect the passive functions of downstream components (e.g., reduction in flow, drop in pressure, reduction in heat transfer) due to flow blockage and for components with a pressure boundary function that could experience accelerated corrosion due to coating degradation.

(3.a) Component with internal Service Level III or Other Coating	**(3.b.i)** Coating Installation Records Available	**(3.b.i)** *Installation records, if available, used to apply the coating included material manufacturer installation specifications.*
Piping		
Fire protection carbon dioxide	No	N/A
High pressure fire protection	No	N/A
Makeup water treatment plant	No	N/A
Hypochlorite	No	N/A
Essential raw cooling water	Yes	The coating (Belzona) was applied in accordance with the coating manufacturer's specification or as directed by TVA Engineering.
Tanks		
HPFP water storage	No	N/A
Clear well	No	N/A
Caustic	Yes	Lined per TVA Spec. Section 27 [see drawing 166365, contract 71C30-92627-1]
Cation	No	N/A
Potable water	Yes	AWWA D102-62T Standard for Painting
Bulk chemical storage tank	No	N/A
Caustic batching	No	N/A
Cask decontamination collector	No	N/A
Main feed pump turbine oil	No	N/A
Gland seal water storage	No	N/A
SI pump lube oil reservoirs	No	N/A

(3.a) Component with internal Service Level III or Other Coating	**(3.b.i)** Coating Installation Records Available	**(3.b.i)** *Installation records, if available, used to apply the coating included material manufacturer installation specifications.*
Pressurizer relief	No	N/A
EDG 7 day storage	Yes	The coating (Belzona) was applied in accordance with the coating manufacturer's specification or as directed by TVA Engineering.
Heat Exchangers		
Electric board room chiller packages (A-A and B-B)	Yes	The coating (Belzona) was applied in accordance with the coating manufacturer's specification or as directed by TVA Engineering.
Incore instrument room water chiller package B	Yes	The coating (Belzona) was applied in accordance with the coating manufacturer's specification or as directed by TVA Engineering.

b(ii). Visual inspections are used to assess coating condition.
b(iii). The monitored parameter is the coated component surface condition.

b(iv). Initial inspections will begin no later than the last scheduled refueling outage prior to the period of extended operation (PEO). 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 six years. If no indications are found during inspection of one train, the redundant train would not be inspected.
ii. If the inspection results do not meet (i), but a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage.
iii. If coating degradation is observed that required repair or replacement, or newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating.

Commitment **#24.B** has been added.

b(v). The extent of inspections for coated tanks and heat exchangers is different than that for piping. The visible portions of coated tanks and heat exchangers are inspected upon disassembly or entry. The inspection of coated piping is based on accessibility (i.e., the ends of the piping and the length of available borescope equipment). A 20 percent sample of the pipe coating or a maximum of 25 locations will be inspected for each combination of coating type, material protected by the coating, and environment.

b(vi). Coating inspections are performed by individuals certified to ANSI N45.2.6, "Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants." The 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."

b(vii). The Periodic Surveillance and Preventive Maintenance (PSPM) Program described in LRA B.1.31 is structured to maintain components in a manner that permits them to

perform their design function. The program establishes the frequency and types of maintenance to be performed on equipment commensurate with its importance to safety, effect on plant operation, and replacement cost, with consideration for the degree of inherent reliability built into individual components. Relevant information about the equipment maintenance activity, including as-found conditions, is recorded and reviewed. The as-found conditions are trended and used to adjust the time interval between preventive maintenance activities to ensure that the monitored components can continue to perform their design function until the next inspection. An individual knowledgeable and experienced in nuclear coatings work will prepare reports that include 1) the location of all areas identified with deterioration, 2) a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next inspection, and 3) where available, photographs indexed to inspection locations.

b(viii). The following acceptance criteria are utilized: 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.

b(ix). Corrective actions for unacceptable inspection findings will be determined in accordance with the SQN 10 CFR 50 Appendix B Corrective Action Program (CAP).

b(x). The PSPM Program described in LRA B.1.31 is enhanced to include verification of coating integrity of selected 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.1.13 is enhanced in the response to SQN RAI 3.0.3-1 Request #4 to address the coatings in the fire water storage tanks.

The Service Water Integrity Program described in LRA B.1.38 is enhanced to address coating acceptance criteria, qualifications for personnel performing coating inspections and evaluating coating findings, and documentation of coating inspections.

c. Changes to **LRA Section A.1.31**, Periodic Surveillance and Preventive Maintenance Program, follow with additions underlined.

"The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages for specific components' aging effects not managed by other aging management programs, including loss of material, fouling, cracking, <u>loss of coating integrity</u>, and change in material properties.

Each inspection occurs at least once every five years<u>, with the exception of coating inspections for which frequency is based on coating condition</u>. For each activity that refers to a representative sample, a representative sample is 20 percent of the population (defined as components having the same material, environment, and aging effect combination) with a maximum of 25 components.

Credit for program activities has been taken in the aging management review of systems, structures and components as described below.

- <u>Prior to the PEO, perform a visual inspection of a 20 percent sample of the following coated piping systems or a maximum of 25 locations for each combination of type of coating, material the coating is protecting, and environment.</u> <u>Visually inspect the</u>

surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering.

i. Fire protection carbon dioxide (galvanized piping)
ii. High pressure fire protection (cement lined piping)
iii. Makeup water treatment plant (where Saran and Polypropylene applied)
iv. Hypochlorite (Polypropylene, Kynar, Teflon, and concrete)
v. Essential raw cooling water (where Belzona applied)

- Prior to the PEO, perform a visual inspection of the following coated tanks and heat exchangers. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering.

Tanks

i. Clear well (where Epoxy-Phenolic coating/Wisconsin protective coating Plastite No. 7155 or equal applied)
ii. Caustic (where TVA specs -Section 27 applied (drawing 116365, contract 71C30-92627-1))
iii. Cation (where 3/16 inch of rubber applied)
iv. Potable water (where AWWA D102-62T standard for painting Section 3.1 No. 2, 3, or 4 applied)
v. Bulk chemical (where rubber lining applied)
vi. Caustic batching (where 3/16" rubber lined with chlorinated rubber compound applied)
vii. Cask decontamination (where 2 coats Red Lead in oil, Fed SPEC TTP-85 Type II applied)
viii. Main feed pump turbine oil (where coating applied)
ix. Gland seal water (where red oil based paint applied)
x. Safety injection lube oil reservoir (where 0.006 inch plastic coating applied)
xi. Pressurizer relief (where Ambercoat 55 applied)
xii. EDG 7 day storage (where Belzona applied)

Heat Exchangers

i. Electric board room chiller packages (where Belzona applied)
ii. Incore instrument room water chiller package B (where Belzona applied)

- Include the following loss of coating integrity acceptance criteria (1) peeling and delamination are not permitted, (2) cracking is not permitted 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.
- 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."
- 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.
- Perform subsequent inspections of coatings based on the following.
  i. If no flaking, debonding, 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 six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would 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 every other refueling outage.
  iii. If coating degradation is observed that required newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating."

Commitment **#24** will implement the intents made in the statements above and for LRA Section B.1.31 changes stated below.

Changes to **LRA Section B.1.31**, Periodic Surveillance and Preventive Maintenance Program (PSPM) follow with additions underlined.

"The Periodic Surveillance and Preventive Maintenance (PSPM) Program manages for specific components' aging effects not managed by other aging management programs, including loss of material, fouling, cracking, loss of coating integrity, and change in material properties.

Initial coating inspections will begin no later than the last scheduled refueling outage prior to the PEO. Subsequent coating inspections will be performed based on the following.

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 six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would 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 every other refueling outage.

iii. If coating degradation is observed that required newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating.

4. Detection of Aging Effects

Preventive maintenance activities and periodic surveillances provide for periodic component inspections to detect aging effects. 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 elastomeric components and (2) visual inspections or other NDE techniques for metallic components. Inspections are performed by personnel qualified to perform the 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, and (3) for loss of coating integrity (a) no peeling or delamination, (b) no cracking if accompanied by delamination or loss of adhesion, and (c) no blisters unless completely surrounded by sound coating bonded to the surface.

Element Affected	Enhancement
3. Parameters Monitored/Inspected 4. Detection of Aging Effects	Prior to the PEO, perform a visual inspection of a 20 percent sample of the following coated piping systems or a maximum of 25 locations for each combination of type of coating, material the coating is protecting, and environment combination. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. i. Fire protection carbon dioxide (galvanized piping) ii. High pressure fire protection (cement lined piping) iii. Makeup water treatment plant (where Saran and Polypropylene applied) iv. Hypochlorite (Polypropylene, Kynar, Teflon, and concrete) v. Essential raw cooling water (where Belzona applied)
3. Parameters Monitored/Inspected 4. Detection of Aging Effects	Prior to the PEO, perform a visual inspection of the following coated tanks and heat exchangers. Visually inspect the surface condition of the coated components to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering. **Tanks** i. Clear well (where Epoxy-Phenolic coating/Wisconsin protective coating Plastite No. 7155 or equal applied) ii. Caustic (where TVA specs - Section 27 applied, drawing 166365; contract 71C30-92627-1) iii. Cation (where 3/16 inch of rubber applied) iv. Potable water (where AWWA D102-62T standard for painting Section 3.1 No. 2, 3, or 4 applied) v. Bulk chemical (where rubber lining applied) vi. Caustic batching (where 3/16" rubber lined with chlorinated rubber compound applied) vii. Cask decontamination (where 2 coats Red Lead in oil , Fed SPEC TTP-85 Type II applied) viii. Main feed pump turbine oil (where coating applied) ix. Gland seal water (where red oil based paint applied) x. Safety injection lube oil reservoir (where 0.006 inch plastic coating applied) xi. Pressurizer relief (where Ambercoat 55 applied) xii. EDG 7 day storage (where Belzona applied) **Heat Exchangers** i. Electric board room chiller package (where Belzona applied) ii. Incore instrument room water chiller package B (where Belzona applied)

6. Acceptance Criteria	Include the following acceptance criteria for loss of coating integrity: (1) peeling and delamination are not permitted, (2) cracking is not permitted 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.

3. Parameters Monitored/Inspected 4. Detection of Aging Effects	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."
5. Monitoring and Trending	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.
4. Detection of Aging Effects	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."
3. Parameters Monitored/Inspected 4. Detection of Aging Effects	Perform subsequent inspections of coatings based on the following. i. If no flaking, debonding, 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 six years. If the coating is inspected on one train and no indications are found, the same coating on the redundant train would not be inspected during that inspection interval. ii. If the inspection results do not meet (i), but a coating specialist has determined that no remediation is required, then subsequent inspections will be conducted every other refueling outage. iii. If coating degradation is observed that required newly installed coatings, subsequent inspections will occur during each of the next two refueling outage intervals to establish a performance trend on the coating.

Changes to **LRA Section A.1.38**, Service Water Integrity Program follow with additions underlined

"The Service Water Integrity Program manages loss of material and fouling for components fabricated from carbon steel, carbon steel clad with stainless steel, cast iron, copper alloy, nickel alloy, or stainless steel exposed to ERCW as described in the SQN response to NRC GL 89-13. The program includes (a) surveillance and control techniques to manage effects of biofouling, corrosion, erosion, coating failures, and silting; (b) tests to verify heat transfer capability of heat exchangers important to safety; (c) system walkdowns to ensure compliance with the licensing basis; and (d) routine inspections and maintenance.

The Service Water Integrity Program will be enhanced as follows.

- Revise Service Water Integrity Program procedures to perform periodic visual inspections to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering in heat exchangers credited in the NRC Generic Letter (GL) 89-13 response. Include the following coating integrity acceptance criteria: (1) peeling and delamination are not permitted, (2) cracking is not permitted 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.

- 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."

Changes to **LRA Section B.1.38**, Service Water Integrity Program follow with additions underlined and deletions marked through.

"Enhancements

~~None~~The following enhancement will be implemented prior to the PEO.

Element Affected	Enhancement
3. Parameters Monitored/Inspected	Revise Service Water Integrity Program procedures to monitor the condition of coated surfaces in the heat exchangers credited in the response to NRC Generic Letter (GL) 89-13 response.
4. Detection of aging Effect	Revise the Service Water Integrity Program procedures to perform periodic visual inspections to manage loss of coating integrity due to cracking, debonding, delamination, peeling, flaking, and blistering in heat exchangers credited in the NRC Generic Letter (GL) 89-13 response.
6. Acceptance Criteria	Revise the Service Water Integrity Program procedures to include the following coating integrity acceptance criteria: (1) peeling and delamination are not permitted, (2) cracking is not permitted 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.
5. Monitoring and Trending	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.

"

Commitment **#38** has been added.

Changes to **LRA Table 3.3.2-1** follow with additions underlined.

Table 3.3.2-3: Fire Protection CO2 and RCP Oil Collection System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping	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

Changes to **LRA Table 3.3.2-1** follow with additions underlined.

Table 3.3.2-1: Fuel Oil System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Piping	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

Changes to **LRA Table 3.3.2-1** follow with additions underlined.

Table 3.3.2-2: High Pressure Fire Protection - Water System

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	Raw Water (int.)	Loss of coating integrity	Fire Water System Program	-	-	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

Changes to **LRA Table 3.3.2-17-6** follow with additions underlined.

Table 3.3.2-17-6: High Pressure Fire Protection - 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
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

Changes to **LRA Table 3.3.2-17-7** follow with additions underlined.

Table 3.3.2-17-7: Water treatment System and Makeup Water Treatment Plant, 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
Piping	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
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

Changes to **LRA Table 3.3.2-17-19** follow with additions underlined.

Table 3.3.2-17-19: Hypochlorite 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
Piping	Pressure boundary	Metal with Service Level III or other internal coating	Treaded 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	Treaded Water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.3.2-17-23** follow with additions underlined.

Table 3.3.2-17-23: Chemical and Volume Control 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	Metal with Service Level III or other internal coating	Treated Water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.3.2-17-25** follow with additions underlined.

Table 3.3.2-17-25: Essential Raw Cooling Water Systems, 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
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

Changes to **LRA Table 3.3.2-17-27** follow with additions underlined.

Table 3.3.2-17-27: Waste Disposal Systems, 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	Metal with Service Level III or other internal coating	Waste water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.3.2-17-8** follow with additions underlined.

Table 3.3.2-17-8: Potable (Treated Water) Water Distribution 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	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.2.2-1** follow with additions underlined.

Table 3.2.2-1: Safety Injection System

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	Lube oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.3.2-17-3** follow with additions underlined.

Table 3.3.2-17-3: Central Lubricating Oil 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	Metal with Service Level III or other internal coating	Lube oil (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.3.2-17-14** follow with additions underlined.

Table 3.3.2-17-14: Gland Seal 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	Metal with Service Level III or other internal coating	Treated water (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.1.2-5** follow with additions underlined.

Table 3.1.2-5: Reactor Coolant 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	Metal with Service Level III or other internal coating	Treated borated water > 140°F (int.)	Loss of coating integrity	Periodic Surveillance and Preventive Maintenance Program	-	-	H

Changes to **LRA Table 3.3.2-6** follow with additions underlined.

Table 3.3.2-6: Control Building HVAC System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat exchanger (Channel Head)	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (int.)	Loss of coating integrity	Service Water Integrity Program	-	-	H

Changes to **LRA Table 3.3.2-5** follow with additions underlined.

Table 3.3.2-5: Aux Building and Reactor Building Gas Treatment/Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Heat exchanger (channel head)	Pressure boundary	Metal with Service Level III or other internal coating	Raw water (int.)	Loss of coating integrity	Service Water Integrity Program	-	-	H

Set 10: RAI 3.0.3-1, Request 4

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 this OE.

These issues are related to the following, as described in detail below:

4. *Managing aging effects of fire water system components*

Issue:

4. *Managing aging effects of fire water system components*

Industry OE has indicated that flow blockages have occurred in dry sprinkler piping that would have resulted in failure of the sprinklers to deliver the required flow to combat a fire. This OE is described in NRC Information Notice (IN) 2013-06, Corrosion in Fire Protection Piping Due to Air and Water Interaction." The common cause is air and water interactions leading to accelerated corrosion that occurred in normally dry fire water piping that had been subject to inadvertent flow or flow tested, and which may not have been properly drained. As stated in IN 2013-06, had inspections been conducted to National Fire Protection Association (NFPA) 25 2011 Edition, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," the obstructions may have been detected. As such, in regard to the recommendations in GALL Report AMP XI.M27, "Fire Water System," and GALL Report AMP XI.M29, the staff position is as follows:

a. *The tests and inspections listed in Table 4a, "Fire Water System Inspection and Testing Recommendations," of this RAI should be conducted.*
b. *Wall thickness evaluations used as an alternative instead of flow tests or internal visual examinations for managing flow blockage should not be credited for aging management because external wall thickness measurements may not be capable of identifying when sufficient general corrosion has occurred such that the corrosion products cause flow blockage. The first enhancement associated with the "detection of aging effects" program element of the Fire Water System Program states that, "[w]all 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." It is not clear to the staff whether these volumetric examinations are in addition to periodic flow tests or internal examinations, or would replace this testing.*
c. *If internal visual inspections detect surface irregularities because of corrosion, follow-up volumetric examinations are to be performed. These follow-up exams are necessary to ensure that there is sufficient wall thickness in the vicinity of the irregularity.*
d. *For portions of water-based fire protection system components that are periodically subjected to flow but designed to be normally dry, such as dry-pipe or preaction sprinkler system piping and valves, augmented inspections should be performed in the portions of this piping that are not configured to completely drain. The augmented inspections should consist of internal visual examination or full flow testing of the entire portion that is not configured to completely drain. Given the*

potential for accelerated corrosion in the portions of this piping that are not configured to completely drain, periodic wall thickness measurements should be conducted.

e. *The inspection requirements in NFPA 25 Chapter 9, "Water Storage Tanks," are different than the recommendations in GALL Report AMP XI.M29. For example, NFPA 25 states that external inspections are conducted quarterly and interior inspections are conducted on a 3-year interval if the tank does not have internal corrosion protection; otherwise, the inspections are conducted on a 5-year interval. In contrast, GALL Report AMP XI.M29 recommends that external inspections occur on a refueling outage interval and internal inspections are conducted every 10 years. Fire water storage tanks should be inspected to the requirements of NFPA 25.*

Request:

4. *Managing aging effects of fire water system components*
   a. *State that inspections and testing of in-scope fire water system components will be conducted in accordance with Table 4a, or provide justification for any portions that will not be inspected or tested in this manner.*
   b. *State whether the enhancement to use wall thickness evaluations is in lieu of conducting flow tests or internal visual examinations, and if it is, state the basis for why wall thickness measurements in the absence of flow testing or internal visual examinations provide reasonable assurance that the intended functions of in-scope fire water system components will be maintained consistent with the CLB for the PEO.*
   c. *Add a requirement to the program to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness, or state the basis for why visual inspections alone will provide reasonable assurance that the intended functions of in-scope fire water system components will be maintained consistent with the CLB for the PEO.*
   d. *For portions of water-based fire protection system components that are periodically subjected to flow but designed to be normally dry, such as dry-pipe or preaction sprinkler system piping and valves, but not configured to completely drain, state the following:*
      i. *The inspection method to ensure that fouling is not occurring.*
      ii. *The parameters to be inspected.*
      iii. *When inspections will commence and the frequency of subsequent inspections.*
      iv. *The extent of inspections and the basis for the extent of inspections if it is not 100 percent.*
      v. *Acceptance criteria.*
      vi. *How much of this piping will be periodically inspected for wall thickness and how often the inspections will occur.*
   e. *Revise the Aboveground Metallic Tanks Program to not include the fire water storage tank and include this tank in the scope of the Fire Water System Program. In addition, state that the tank inspections will be in accordance with the inspections requirements of NFPA 25. Alternatively, state why conducting inspections in accordance with the Aboveground Metallic Tanks Program provides reasonable assurance that the intended functions of fire water storage tank will be maintained consistent with the CLB for the PEO.*
   f. *State how LRA Section 3 Table 2s and Appendices A.1.13 and B.1.13 will be revised to address the above changes.*

Table 4a *Fire Water System Inspection and Testing Recommendations*[1,2,5]	
Description	*NFPA 25 Section*
Sprinkler Systems	
Sprinkler inspections	*5.2.1.1*
Pipe and fitting inspections	*5.2.2*
Hanger and seismic brace inspections	*5.2.3*
Sprinkler testing	*5.3*
Obstruction, internal inspection of piping	*14.2*[4] *and 14.3*
Standpipe and Hose Systems	
Piping inspections	*6.2.1*
Flow tests	*6.3.1*
Hydrostatic tests	*6.3.2*
Private Fire Service Mains	
Exposed piping	*7.2.2.1*
Testing	*7.3.1, 7.3.2, 7.3.3.1*
Fire Pumps	
Suction screens	*8.3.3.7*
Water Storage Tanks	
Exterior Inspections	*9.2.5.5*
Interior inspections	*9.2.6*[5]*, 9.2.7*
Valves and System-Wide Testing	
Main drain test	*13.2.5*
Preaction valves and deluge valves	*13.4.3.2.2 - 13.4.3.2.8*
Dry pipe valves and quick opening devices	*13.4.4.2.2 - 13.4.4.2.3, 13.4.4.2.9*
Pressure reducing valves and relief valves	*13.5.1.2, 13.5.2.2, 13.5.3.2, 13.5.4.3, 13.5.5.2*
Hose Valves	*13.5.6.1.7*
Water Fixed Spray Systems	
Strainers (annual and after each system actuation)	*10.2.1.6, 10.2.1.7, 10.2.7*
Water supply	*10.2.6.2*
System components (annual and after each system actuation)	*10.2.4*
Operation Test (annual)	*10.3.4, 10.3.5, 10.4.1*
Foam Water Sprinkler Systems	
System piping and fittings	*11.2.3. (1), (2)*
Water supply	*11.2.6.2*

Strainers (quarterly)	*11.2.7.1*
Storage tanks (external – quarterly)	*11.2.9.5.1.2 (2)*
Operational Test Discharge Patterns (annually)	*11.3.2.6, 11.3.2.7, 11.3.3*
Storage tanks (internal – 10 years)	*11.4.3, 11.4.4.2, 11.4.5, 11.4.6.4, 11.4.7.4*

1. *All terms and references are to NFPA 25 2011 Edition. The staff is referring to NFPA 25 2011 Edition as a common reference for the description of the scope and periodicity of specific inspections and tests. It should not be inferred that the CLB needs to be revised to include all the inspection, testing and maintenance requirements of this document. The above inspections and tests are related to the management of applicable aging effects for passive long-lived in-scope components in the fire water system. Inspections and tests not related to the above are to be conducted in accordance with the current licensing basis. If the current licensing basis states more frequent inspections than required by NFPA 25, the current licensing basis should be met.*
2. *A reference to a section includes all sub-bullets unless otherwise noted (e.g., a reference to 5.2.1.1 includes 5.2.1.1.1 through 5.2.1.1.7).*
3. *The alternative nondestructive examination methods permitted by 14.2.1.1 are limited to those that can ensure that flow blockage will not occur.*
4. *In regard to Section 9.2.6.4, the threshold for taking action required in Section 9.2.7 is as follows: pitting and general corrosion beyond nominal wall depth and any coating failure where bare metal is exposed. Blisters should be repaired. Adhesion testing should be performed in the vicinity of blisters even though bare metal may not have been exposed.*
5. *Items in areas that are inaccessible for safety considerations due to factors such as continuous process operations and energized electrical equipment shall be inspected during each scheduled shutdown but not more than every refueling outage interval.*

TVA Response to RAI 3.0.3-1, Request 4, Managing Aging Effects of Fire Water System

a. Table 4a was originally provided to TVA in the Set 10, August 2, 2013 RAI, and later revised via an e-mail from NRC Project Manager on 9/26/2013, ADAMS No. ML13270A037. With the incorporation of the enhancements listed in Response f. below, the inspections and testing of in-scope fire water system components will be conducted in accordance with relevant guidance of the NFPA 25 (2011 edition) sections listed in Table 4a with exceptions described below.

Modified **Table 4a** Fire Water System Inspection and Testing Recommendations[1,2,5]	
Description	NFPA 25 Section
Sprinkler Systems	
Sprinkler inspections[5]	5.2.1.1
Sprinkler testing	5.3.1
Standpipe and Hose Systems	
Flow tests	6.3.1
Private Fire Service Mains	
Underground and exposed piping flow tests	7.3.1
Hydrants	7.3.2
Fire Pumps	
Suction screens	8.3.3.7
Water Storage Tanks	
Exterior inspections	9.2.5.5
Interior inspections	9.2.6[4], 9.2.7
Valves and System-Wide Testing	
Main drain test	13.2.5
Deluge valves[5]	13.4.3.2.2 through 13.4.3.2.5
Water Spray Fixed Systems	
Strainers (refueling outage interval and after each system actuation)	10.2.1.6, 10.2.1.7, 10.2.7
Operation test (refueling outage interval)	10.3.4.3
Foam Water Sprinkler Systems	
Strainers (refueling outage interval and after each system actuation)	11.2.7.1
Operational Test Discharge Patterns (annually)[6]	11.3.2.6
Storage tanks (internal – 10 years)	Visual inspection for internal corrosion
Obstruction Investigation	
Obstruction, internal inspection of piping[3]	14.2 and 14.3

1. All terms and references are to the 2011 Edition of NFPA 25. The NRC staff cites the 2011 Edition of NFPA 25 for the description of the scope and periodicity of specific inspections and tests. This table specifies those inspections and tests that are related to age-managing applicable aging effects associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system. Inspections and tests not related to the above should continue to be conducted in accordance with the plant's current licensing basis. If the current licensing basis specifies more frequent inspections than required by NFPA 25 or this table, the plant's current licensing basis should be continue to be met.
2. A reference to a section includes all sub-bullets unless otherwise noted (e.g., a reference to 5.2.1.1 includes 5.2.1.1.1 through 5.2.1.1.7).
3. The alternative nondestructive examination methods permitted by 14.2.1.1 and 14.3.2.3 are limited to those that can ensure that flow blockage will not occur.
4. In regard to Section 9.2.6.4, the threshold for taking action required in Section 9.2.7 is as follows: pitting and general corrosion to below nominal wall depth and any coating failure in which bare metal is exposed. Blisters should be repaired. Adhesion testing should be performed in the vicinity of blisters even though bare metal might not have been exposed. Regardless of conditions observed on the internal surfaces of the tank, bottom-thickness measurements should be taken on each tank during the first 10-year period of the PEO.
5. Items in areas that are inaccessible because of safety considerations such as those raised by continuous process operations, radiological dose, or energized electrical equipment shall be inspected during each scheduled shutdown but not more often than every refueling outage interval.
6. Where the nature of the protected property is such that foam cannot be discharged, the nozzles or open sprinklers shall be inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed.

Exceptions to the Modified Table 4a

- Inspections specified in Sections 5.2.1.1, 5.2.2 and 5.2.3 are performed on an 18-month basis versus an annual basis. The frequency of once every 18 months is appropriate based on the lack of past inspection findings and the need to perform some inspections during a refueling outage.
- Sections 14.2.1 and 14.2.2: Section 14.2.1 specifies an inspection of piping and branch line conditions every five years unless there are multiple wet pipe systems in a building. For multiple wet pipe systems in a building, Section 14.2.2 allows an inspection on every other wet pipe system every five years. The inspection consists of opening a flushing connection at the end of one main and removing a sprinkler toward the end of one branch line for the purpose of inspecting for the presence of foreign material. SQN is taking the following exception to Sections 14.2.1 and 14.2.2. SQN performs internal inspection of the high pressure fire water (HPFP) system strainers every 36 months. If foreign material is identified, the condition is entered into the CAP. In the last 10 years, only one incident of organic material (clam shells) was identified in the strainer. It was determined that the clam shells entered the system before the HPFP system was switched from raw water to potable water in 1998. SQN will perform a one-time visual inspection using the methodology described in NFPA-25 Section 14.2.1 prior to the PEO to verify there are no foreign materials in the dry portions of the fire water system (i.e., those portions downstream

of deluge and preaction valves). Any additional inspections of the dry portion of the fire water system in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the one-time inspection results. See the enhancement in Response f. below and Commitment **#9.G**.

- Section 6.3.1 addresses conducting a flow test. SQN is taking an exception to conducting a flow test and a main drain test of each zone of the automatic standpipe system. Every three years, the station tests the highest elevation areas in the ERCW building to ensure sufficient pressure and flow at lower elevations. For the fire water hoses credited in the NRC-approved Fire Protection Report, the station ensures that the required minimum flow is established every three years. For other fire water hose stations, open flow paths through each hose station is verified every five years. Additional flow testing of the automatic standpipe system is a risk-significant activity due to the potential for water contacting critical equipment in the area. In addition, flowing water in the radiological areas may result in additional radwaste. Any flow blockage or abnormal discharge identified during flow testing is identified and entered into the CAP.

  Not performing flow testing in the radiological controlled area and areas that contain critical equipment required for normal and shutdown operations eliminates a risk-significant activity and the potential to create additional radwaste. Because the system is continuously pressurized with potable water, an open flow path is assured without the need to perform additional flow testing.

- Section 7.3.1 addresses flow testing of underground and exposed piping. SQN is taking an exception to flow testing additional underground and exposed piping within buildings for the same reason stated in the exception to Section 6.3.1 above. The station performs testing to determine friction loss characteristics on most of the exterior fire water system piping. The tests assess the pressure loss of the various pipe segments. The tests are performed every three years and the results are trended. Based on ten years' of test results for underground piping and the use of potable water, there is reasonable assurance of an open flow path without performing additional flow testing. In addition, hydrants are tested annually.

  Based on the current testing and trending, the addition of a risk-significant activity, and the production of additional radwaste in radiological controlled areas is not warranted.

- Section 13.4.3.2.2 specifies full flow testing of deluge valves. SQN is taking an exception to performing deluge valve testing annually at full flow in indoor areas containing equipment critical to the operation of the plant. Opening a deluge valve and allowing flow out of the open sprinkler heads in areas with critical equipment is considered a risk-significant activity. In addition, flow testing in the RCA would result in additional radwaste.

Based on the testing and trending, the additional deluge valve testing is not warranted due to the addition of a risk-significant activity, the production of additional radwaste in radiological controlled areas.

b. The enhancement described in LRA Sections A.1.13 and B.1.13 allows the use of non-intrusive techniques (e.g., volumetric testing) in lieu of conducting flow testing or internal inspections to detect flow blockage. According to the NFPA-25 (2011) handbook, the use of x-ray, ultra sound, and remote video techniques can be used in lieu of impairing the system to conduct visual inspections. The use of these techniques provides reasonable assurance that the effects of aging will be managed such that the fire water system components will continue to perform their intended functions consistent with the current licensing basis through the PEO.

c. An enhancement to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could indicate wall thickness below nominal pipe wall thickness has been added to LRA Sections A.1.13 and B.1.13 as discussed in the enhancement listed in Response f. below.

d. The portions of the fire water system that are periodically subject to flow, but designed to be normally dry, such as dry-pipe or preaction sprinkler system piping and valves, will be inspected prior to the PEO. See Commitment **#9.G**. For those piping sections where drainage is not occurring as expected, the following actions will be performed.
   i. A representative sample of components such as sprinkler heads or couplings will be removed prior to the PEO and a visual internal inspection or non-intrusive testing will be performed to verify there are no signs of abnormal corrosion (wall thickness loss) or blockage. Any signs of abnormal corrosion or blockage will be entered into the CAP.
   ii. The monitored parameter is the condition of the internal surface.
   iii. The inspections will be performed prior to the PEO. The frequency of subsequent inspections will be based on the results of the initial inspections.
   iv. A representative sample is defined as 20 percent of each population with the same material, environment, and aging effect combination with a maximum of 25 inspections. The percentage inspected is the percent of total length of dry piping that may be periodically wetted or the percentage of the total number of discrete locations. This is consistent with representative samples for other aging management programs.
   v. The acceptance criteria will be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged) and no surface irregularities that could indicate wall loss to below nominal pipe wall thickness.
   vi. Wall thickness measurements will be performed if internal visual inspections detect surface irregularities that could indicate wall loss to below nominal pipe wall thickness. See the enhancement in Response f. below.

e. The fire water tanks have been removed from the Above Ground Metallic Tanks Program and included in the Fire Water Systems Program. The fire water storage tanks will be inspected in accordance with NFPA-25 (2011 Ed.) requirements. See Commitment **#9.J**.

f. The change to **LRA Section A.1.1** follows with additions underlined.

"The Aboveground Metallic Tanks Program manages loss of material and cracking for the outer surfaces of the aboveground metallic tanks (excluding the fire water storage tanks) using periodic visual inspections on tanks within the scope of license renewal as delineated in 10 CFR 54.4. For in-scope painted tanks, the program monitors the surface condition for blistering, flaking, cracking, peeling, discoloration, underlying rust, and physical damage. For in-scope stainless steel tanks, the program will monitor surface condition to assure a clean, shiny surface with no visible leaks. The visible exterior portions of the tanks will be inspected at least once every refueling cycle.

This program also manages the bottom surfaces of aboveground metallic tanks, which are constructed on a ring of concrete and oil-filled sand. The program requires ultrasonic testing (UT) of the tank bottoms to assess the thickness against the thickness specified in the design specification. The UT testing of the tank bottoms will be performed at least once within the five years prior to the PEO and whenever the tanks are drained during the PEO.

This program will be implemented prior to the PEO."

The change to **LRA Section B.1.1** follows with additions underlined.

"The Aboveground Metallic Tanks Program is a new program that will manage loss of material and cracking for the outer surfaces of the aboveground metallic tanks (excluding the fire water storage tanks) using periodic visual inspections on tanks within the scope of the program as delineated in 10 CFR 54.4. Preventive measures were applied during construction, such as using the appropriate materials, protective coatings, and elevation as specified in design and installation specifications. For in-scope painted tanks, the program monitors the surface condition for blistering, flaking, cracking, peeling, discoloration, underlying rust, and physical damage. For in-scope stainless steel tanks, the program will monitor surface condition to assure a clean, shiny surface with no visible leaks. The visible exterior portions of the tanks will be inspected at least once every refueling cycle.

This program will also manage the bottom surface of aboveground metallic tanks, which are constructed on a ring of concrete and oil-filled sand. The program will require ultrasonic testing (UT) of the tank bottoms to assess the thickness against the thickness specified in the design specification. The UT testing of the tank bottoms will be performed at least once within the five years prior to the period of extended operation and whenever the tanks are drained during the period of extended operation.

In accordance with installation and design specifications, the tanks do not employ caulking or sealant at the concrete/tank interface.

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

The changes to **LRA Section A.1.13** follow with additions underlined and deletions lined through.

"The Fire Water System Program manages loss of material and fouling for components in fire protection systems (including the fire water storage tanks). The program includes periodic flushing and system performance testing in accordance with the applicable National Fire Protection Association (NFPA) commitments as described in the Fire Protection Report. System pressure is monitored such that loss of pressure is immediately detected and corrective action initiated. Portions of the system exposed to water are internally visually inspected. Sprinkler heads that have been in place for 50 years are tested in accordance with NFPA 25 Section 5.3.1 if not replaced."

- Revise Fire Water System Program procedures to ensure ~~a representative sample of~~ sprinkler heads ~~will be~~ are tested ~~or replaced before the end of the 50-year sprinkler head service life and at ten-year intervals thereafter during the extended period of operation.~~ in accordance with NFPA-25 (2011 Edition), Section 5.3.1. ~~defines a representative sample of sprinklers to consist of a minimum of not less than four sprinklers or one percent of the number of sprinklers per individual sprinkler sample, whichever is greater. If the option to replace the sprinklers is chosen, all sprinkler heads that have been in service for 50 years will be replaced.~~

- Revise Fire Water System Program procedures to ~~include~~ periodically remove a representative sample of components such as sprinkler heads or couplings prior to the PEO and perform a visual internal inspection of dry fire water system piping ~~internals~~ for evidence of corrosion, ~~and~~ loss of wall thickness, and foreign material that may result in flow blockage using the methodology described in NFPA-25 Section 14.2.1. This includes those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring. The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Any additional inspections in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the initial inspection results.

- Revise Fire Water System Program procedures to perform an obstruction evaluation in accordance with NFPA-25 (2011 Edition), Section 14.3.1.

- Revise Fire Water System Program procedures to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness.

- Revise Fire Water System Program procedures to annually inspect the fire water storage tank exterior painted surface for signs of degradation. If degradation is identified, conduct follow-up volumetric examinations to ensure wall thickness is equal to or exceeds nominal wall thickness.

- Revise Fire Water System Program procedures to include a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Include in the revision direction to perform fire water storage tank interior coating testing, if any degradation is identified, in accordance with ASTM D 3359 or equivalent, a dry film thickness test at random locations to determine overall coating thickness; and a wet sponge test to detect pinholes, cracks or other compromises of the coating. If there is evidence of pitting or corrosion ensure the Fire Water System Program procedures direct performance of an examination to determine wall and bottom thickness.
- Revise Fire Water System Program procedures based on the results of a feasibility study to perform the main drain tests in accordance with NFPA-25 (2011 Edition) Section 13.2.5.
- Revise Fire Water System Program procedures to perform spray head discharge pattern tests from all open spray nozzles to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Where the nature of the protected property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with smoke or some other medium to ensure that the nozzles are not obstructed.

The changes to **LRA Section B.1.13** follow with additions underlined and deletions lined through.

"The Fire Water System Program manages loss of material and fouling for fire protection components (including the fire water storage tanks) that are tested in accordance with the Fire Protection Report.

Consistent with NFPA 25, the SQN program includes system performance testing in accordance with the Fire Protection Report. This periodic full-flow testing includes monitoring the pressure of tested pipe segments, which verifies that system pressure remains adequate for system intended functions. Results are trended. Periodic flushing is also performed in accordance with the Fire Protection Report.

Wall thickness measurements are evaluated to ensure minimum wall thickness is maintained. Wall thickness may be determined by non-intrusive measurement, such as volumetric testing, or as an alternative to non-intrusive testing, by visually monitoring internal surface conditions upon each entry into the system for routine or corrective maintenance. The use of internal visual inspections is acceptable when inspections can be performed (based on past maintenance history) on a representative number of locations. These inspections will be performed before the period of extended operation and at plant-specific intervals based on the initial test results during the period of extended operation. Periodic visual inspections of fire water system internals will monitor surface condition for indications of loss of material.

In addition, the water system pressure is continuously monitored such that loss of pressure is immediately detected and corrective action initiated. If not replaced, sprinkler heads are tested before the end of 50-year sprinkler service life and every ten years thereafter during the period of extended operation. General requirements of the program include testing and maintaining fire detectors and visually inspecting the fire hydrants to detect signs of corrosion. Fire hydrant flow tests are performed annually to ensure the fire hydrants can perform their intended function.

Program acceptance criteria are (a) the water based fire protection system can maintain required pressure, (b) no signs of unacceptable degradation are observed during non-intrusive or visual inspections, (c) minimum design pipe and tank wall thickness is maintained, and (d) no biofouling exists in the sprinkler systems that could cause corrosion in the sprinklers."

Elements Affected	Enhancements
4. Detection of Aging Effect	Revise Fire Water System Program procedures to ensure ~~a representative sample of~~ sprinkler heads ~~will be~~ are tested ~~or replaced before the end of the 50-year sprinkler head service life and at ten-year intervals thereafter during the extended period of operation.~~ in accordance with NFPA-25 (2011 Edition), Section 5.3.1. ~~defines a representative sample of sprinklers to consist of a minimum of not less than four sprinklers or one percent of the number of sprinklers per individual sprinkler sample, whichever is greater. If the option to replace the sprinklers is chosen, all sprinkler heads that have been in service for 50 years will be replaced.~~
4. Detection of Aging Effect	Revise Fire Water Program procedures to perform an obstruction evaluation in accordance with NFPA-25 (2011 Edition), Section 14.3.1.
4. Detection of Aging Effect	Revise Fire Water System Program procedures to ~~include~~ periodically remove a representative sample of components such as sprinkler heads or couplings prior to the PEO and perform a visual internal inspection of dry fire water system piping ~~internals~~ for evidence of corrosion, ~~and~~ loss of wall thickness, and foreign material using the methodology described in NFPA-25 Section 14.2.1. This includes those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring due to design. The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Any additional inspections in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the initial inspection results.
4. Detection of Aging Effect	Revise Fire Water System Program procedures to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness.

4. Detection of Aging Effect	Revise Fire Water System Program procedures to annually inspect the fire water storage tank exterior painted surface for signs of degradation. If degradation is identified, conduct follow-up volumetric examinations to ensure wall thickness is equal to or exceeds nominal wall thickness.
4. Detection of Aging Effect	Revise Fire Water System Program procedures to include a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Include in the revision direction to perform fire water storage tank interior coating testing, if any degradation is identified, in accordance with ASTM D 3359 or equivalent, a dry film thickness test at random locations to determine overall coating thickness; and a wet sponge test to detect pinholes, cracks or other compromises of the coating.
4. Detection of Aging Effect	Revise Fire Water System Program procedures to perform a non-destructive examination to determine wall thickness whenever degradation is identified during internal tank inspections.
4. Detection of Aging Effect	Revise Fire Water System Program procedures based on the results of a feasibility study to perform the main drain tests in accordance with NFPA-25 (2011 Edition) Section 13.2.5.
4. Detection of Aging Effect	Revise Fire Water System Program procedures to perform spray head discharge pattern tests from all open spray nozzles to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Where the nature of the protected property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with smoke or some other medium to ensure that the nozzles are not obstructed.

The changes to affected **LRA Table 3.3.2-2**: High Pressure Fire Protection - Water System, line items and the corresponding **Table 3.3.1** and **3.3.4** line items follow with additions underlined and deletions marked through.

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	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

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 steel tanks, except fire water storage tanks, exposed to outdoor air is managed by the Aboveground Metallic Tanks Program. The Fire Water System Program manages loss of material for fire water storage tanks.
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 most components. Loss of material for steel tanks exposed to concrete or soil is managed by the Aboveground Metallic Tanks Program. The Fire Water System Program manages loss of material for fire water storage tanks exposed to concrete or soil. Loss of material for stainless steel tanks exposed to outdoor air (applies to components in Table 3.2.2-1 only) is managed by the Aboveground Metallic Tanks Program. There are no aluminum or stainless steel tanks exposed to outdoor air in the steam and power conversion systems in the scope of license renewal.

Commitments **#9.C, G – M** have been changed.

Set 10: RAI 3.0.3-1, Request 6

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 this OE.

These issues are related to the following, as described in detail below:

6. Corrosion under insulation

Issue:

6. Corrosion under insulation

During a recent license renewal AMP audit, the staff observed extensive general corrosion (i.e., extent of corrosion from a surface area but not depth of penetration perspective) underneath the insulation removed from an auxiliary feedwater (AFW) suction line. The process fluid temperature was below the dew point for sufficient duration to accumulate condensation on the external pipe surface. NACE, International (NACE), formerly known as National Association of Corrosion Engineers, Standard SP0198-2010, "Control of Corrosion under Thermal Insulation and Fireproofing Materials – A Systems Approach," categorizes this as corrosion under insulation (CUI). In addition, during AMP audits the staff has identified gaps in the proposed aging management methods for insulated outdoor tanks and piping surfaces. To date, these gaps have been associated with insufficient proposed examination of the surfaces under insulation.

The staff recommends periodic representative inspections of in-scope insulated components where the process fluid temperature is below the dew point or where the component is located outdoors. The timing, frequency, and extent of inspections should be as follows:

a. Periodic inspections should be conducted during each 10-year period beginning 5 years before the PEO.
b. For a representative sample of outdoor components, except tanks, and any indoor components operated below the dew point, remove the insulation and inspect a minimum of 20 percent of the in-scope piping length for each material type (i.e., steel, stainless steel, copper alloy, aluminum), or for components where its configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, remove the insulation and inspect any combination of a minimum of 25 1-foot axial length sections and components for each material type. Inspections are conducted in each air environment (e.g., air-outdoor, moist air) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, although indoor air is conditioned, significant moisture can accumulate under insulation during high humidity seasons.
c. For a representative sample of outdoor tanks and indoor tanks operated below the dew point, remove the insulation from either 25 1-square-foot sections or 20 percent of the surface area and inspect the exterior surface of the tank. Distribute the sample inspection points such that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects such as on top of stiffening rings.

d. *Inspection locations should be based on the likelihood of CUI occurring (e.g., alternate wetting and drying in environments where trace contaminants could be present, length of time the system operates below the dewpoint).*
e. *Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, should be credited toward the sample population.*
f. *Subsequent inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation when the following conditions are verified in the initial inspection:*
    i. *No loss of material due to general, pitting or crevice corrosion, beyond that which could have been present during initial construction.*
    ii. *No evidence of SCC.*
    iii. *No evidence of fatigue cracks.*

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 should continue as described above.

Request:

6. *Corrosion under insulation*

    a. *State how LRA Section 3 Table 2s and the appropriate AMPs and corresponding Updated Final Safety Analysis Report (UFSAR) supplements will be revised to address the recommendations discussed above related to CUI for outdoor insulated components and indoor insulated components operated below the dew point. Alternatively, state and justify portions that will not be consistent with the recommendations related to CUI, above*

TVA Response to RAI 3.0.3-1 Request 6 – Corrosion under insulation

The response to Request 6.a. is provided by responding to Issues 6.a. through 6.f. and providing a change to the LRA.

During the PEO, there will be periodic representative inspections of the in-scope mechanical component surfaces under insulation and the insulation exterior surface. Insulated indoor components (with process fluid temperature below the dew point) and outdoor components will be inspected. SQN has procedural control over jacketing and insulation. The following discusses the periodic representative inspections.

a. SQN representative inspections are conducted during each 10-year period beginning 5 years before the PEO.

b1. For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (i.e., steel, stainless steel, copper alloy, aluminum). 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 is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and a minimum of 25

inspections are performed that can be a combination of 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum).

b2. For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period.

If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation.

c. For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square-foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).

d. Inspection locations are 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.

e. If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a small number of inspections of the external moisture barrier of this type of insulation, although not zero, will be performed and credited toward the sample population.

f. 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
- No evidence of cracking
- No evidence of cracking

Nominal degradation is defined as 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.

Changes to **LRA Section A.1.10,** External Surfaces Monitoring Program follow with additions underlined and deletions lined through.

"The External Surfaces Monitoring Program manages aging effects of components fabricated from metallic and polymeric materials through periodic visual inspection of external surfaces during system inspections and walkdowns for evidence of leakage, loss of material (including loss of material due to wear), cracking, and change in material properties. When appropriate for the component and material, physical manipulation is used to augment visual inspections to confirm the absence of elastomer hardening and loss of strength. Inspections will be performed by personal qualified through plant-specific programs, and deficiencies are documented and evaluated under the CAP. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components' intended functions are maintained.

For a representative sample of outdoor insulated components and indoor insulated components operated below the dew point, which have been identified with more than nominal degradation on the exterior of the component, insulation is removed for inspection of the component surface. For a representative sample of indoor insulated components operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface is inspected. These inspections will be conducted during each 10-year period beginning 5 years before the PEO.

The External Surfaces Monitoring Program will be enhanced as follows.

- Revise External Surfaces Monitoring Program procedures to clarify that periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3) will be performed. Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).
- Revise External Surfaces Monitoring Program procedures to include instructions to look for the following related to metallic components:
  - Corrosion and material wastage (loss of material).
  - Leakage from or onto external surfaces (loss of material).
  - Worn, flaking, or oxide-coated surfaces (loss of material).
  - Corrosion stains on thermal insulation (loss of material).
  - Protective coating degradation (cracking, flaking, and blistering).
  - Leakage for detection of cracks on the external surfaces of stainless steel components exposed to an air environment containing halides.
- Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components through physical manipulations of the material, with a sample size for manipulation of at least ten percent of the available surface area. The inspection parameters for polymers shall include the following:
  - Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking).
  - Discoloration.
  - Exposure of internal reinforcement for reinforced elastomers (loss of material).

- Hardening as evidenced by loss of suppleness during manipulation where the component and material can be manipulated.

- ~~Revise External Surfaces Monitoring Program procedures to ensure surfaces that are insulated will be inspected when the external surface is exposed (i.e., during maintenance) at such intervals that would ensure that the components' intended function is maintained.~~Revise External Surfaces Monitoring Program procedures to specify the following for insulated components.
  - Periodic representative inspections are conducted during each 10-year period beginning 5 years before the PEO.
  - For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum). 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 is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and component inspections performed for any combination of a minimum of 25 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum.)
  - For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period.

    If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation.
  - For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).
  - Inspection locations are 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.
  - If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, will be credited toward the sample population.

- 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
  - No evidence of cracking

  Nominal degradation is defined as 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.

- Revise External Surfaces Monitoring Program procedures to include acceptance criteria. Examples include the following:
  - Stainless steel should have a clean shiny surface with no discoloration.
  - Other metals should not have any abnormal surface indications.
  - Flexible polymers should have a uniform surface texture and color with no cracks and no unanticipated dimensional change, no abnormal surface with the material in an as-new condition with respect to hardness, flexibility, physical dimensions, and color.
  - Rigid polymers should have no erosion, cracking, checking or chalks.

Enhancements will be implemented prior to the period of extended operation."

Changes to **LRA Section B.1.10,** External Surfaces Monitoring Program follow with additions underlined and deletions lined through.

"For polymeric materials, the visual inspection will include 100 percent of the accessible components. The sample size of polymeric components that receive physical manipulation is at least ten percent of the available surface area. Acceptance criteria are defined to ensure that the need for corrective action is identified before a loss of intended function(s). For stainless steel a clean shiny surface is expected. For flexible polymers a uniform surface texture (no cracks) and no change in material properties (e.g., hardness, flexibility, physical dimensions, color unchanged from when the material was new) are expected. For rigid polymers no surface changes affecting performance such as erosion, cracking, crazing, checking, and chalking are expected. The acceptance standards include design standards, procedural requirements, current licensing basis, industry codes or standards, and engineering evaluations.

For a representative sample of outdoor insulated components and indoor insulated components operated below the dew point, which have been identified with more than nominal degradation on the exterior of the component, insulation is removed for inspection of the component surface. For a representative sample of indoor insulated components operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface is inspected. These inspections will be conducted during each 10-year period beginning 5 years before the PEO.

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.

Exceptions to NUREG-1801

None

Enhancements

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

Element Affected	Enhancement
1. Scope of Program	Revise External Surfaces Monitoring Program procedures to clarify that periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3) will be performed. Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2).
3. Parameters Monitored or Inspected	Revise External Surfaces Monitoring Program procedures to include instructions to look for the following related to metallic components: • Corrosion and material wastage (loss of material). • Leakage from or onto external surfaces (loss of material). • Worn, flaking, or oxide-coated surfaces (loss of material). • Corrosion stains on thermal insulation (loss of material). • Protective coating degradation (cracking, flaking, and blistering). • Leakage for detection of cracks on the external surfaces of stainless steel components exposed to an air environment containing halides.
3. Parameters Monitored or Inspected	Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components, including manual or physical manipulations of the material, with a sample size for manipulation of at least ten percent of the available surface area. The inspection parameters for polymers shall include the following: • Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking). • Discoloration. • Exposure of internal reinforcement for reinforced elastomers (loss of material). • Hardening as evidenced by loss of suppleness during manipulation where the component and material can be manipulated.
4. Detection of Aging Effects	~~Revise External Surfaces Monitoring Program procedures to ensure surfaces that are insulated will be inspected when the external surface is exposed (i.e., during maintenance) at such intervals that would ensure that the components' intended function is maintained.~~Revise External Surfaces Monitoring Program procedures to specify the following for insulated components: • Periodic representative inspections are conducted during each 10-year period beginning 5 years before the PEO. • For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum). 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 is inspected. Inspected components are 20% of the population of each

	material type with a maximum of 25. Alternatively, insulation is removed and a minimum of 25 inspections are performed that can be a combination of 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum)

4. (continue)	• For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the piping component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period.
	
	If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation.
	
	• For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).
	
	• Inspection locations are 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.
	
	• If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, will be credited toward the sample population.
	
	• 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
	  • No evidence of cracking
	Nominal degradation is defined as 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.

6. Acceptance Criteria	Revise External Surfaces Monitoring Program procedures to include acceptance criteria. Examples include the following: • Stainless steel should have a clean shiny surface with no discoloration.

	• Other metals should not have any abnormal surface indications. • Flexible polymers should have a uniform surface texture and color with no cracks and no unanticipated dimensional change, no abnormal surface with the material in an as-new condition with respect to hardness, flexibility, physical dimensions, and color. • Rigid polymers should have no erosion, cracking, checking or chalks.

The changes to LRA table line items follow with additions underlined.

At the end of **LRA Table 3.2.1** Engineered Safety Features, in Notes for **Table 3.2.2-1** through **Table 3.2.2-5-3**, add the following plant specific note 204.

"204. Program provisions for outdoor insulated components or for indoor insulated components that operate below the dew point apply..

Table 3.2.2-1: Safety Injection System Summary of Aging Management Evaluation

Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 204
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 204
Tank	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 204
Tank	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 204

"

At the end of **LRA Table 3.3.1** Auxiliary Systems, in Notes for **Table 3.3.2-1** through **Table 3.3.2-17-32**, add the following plant specific note 313.

"313. Program provisions for outdoor insulated components or for indoor insulated components that operate below the dew point apply.

Table 3.3.2-2: High Pressure Fire Protection - Water System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-4: Miscellaneous Heating, Ventilating and Air Conditioning Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Tank	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-6: Control Building HVAC System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-11: Essential Raw Cooling Water Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Nickel alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-17-4: Raw Cooling Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Copper alloy	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-17-5: Raw Service Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-17-16: Layup Water Treatment System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 313

Table 3.3.2-17-22: Ice Condenser System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313
Tank	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 313

"

At the end of **LRA Table 3.4.1** Steam and Power Conversion Systems, in Notes for **Table 3.4.2-1** through **3.4.2-3-10**, add the following plant specific note 404.

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

Table 3.4.2-1: Main Steam System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 404

Table 3.4.2-2: Main and Auxiliary Feedwater System Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Aluminum	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Cracking	External Surfaces Monitoring	--	--	H, 404

Table 3.4.2-3-9: Condenser Circulating Water System, Nonsafety-Related Components Affecting Safety-Related Systems Summary of Aging Management Evaluation

Piping	Pressure boundary	Carbon steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Copper alloy > 15% Zn or > 8% Al	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404
Piping	Pressure boundary	Stainless steel	Condensation (ext)	Loss of material	External Surfaces Monitoring	--	--	H, 404

"

Commitments # **6.D** and **F** have been revised.

Set 12: RAI B.1.6-1b and **B.1.6-2b**

In a NRC telecom with TVA on October 23, 2013, the NRC requested clarifications for RAI B.1.6-1a and B.1.6-2a responses. TVA supplements these two responses as follow with additions underlined and deletions lined through.

1. **B.1.6-1b:** Regarding RAI B.1.6-1**a**, from ML13276A018, page E-2 - 42 of 46, Set 12.30d, TVA has added the following two sentences on this page as Commitment **#35.B.**

"To monitor the condition of the access boxes and associated materials, perform visual examinations of all accessible surfaces, including the access box surfaces, cover plate, welds, and gasket sealing surfaces of the access boxes on each unit every other refueling outage with the gasketed access box lid removed."

2. **B.1.6-2b:** Regarding RAI B.1.6-2**a**, from ML13276A018, page E-2 - 45 of 46, Set 12.30d, TVA supplements RAI B.1.6-2a, Response 1.b as follows.

"1.b. As discussed in RAI B.1.6-2a Response 1.a, the volumetric examination is solely an owner-elected examination and is not an examination required by ASME Code Section XI. Although the examinations are performed at the Article IWE-2412 examination frequency, the ASME Code is not the basis for this examination and the examination frequency may be modified during the PEO. Volumetric examinations will continue once every five years ~~at the frequency determined by SQN engineering~~ until the coatings where the SCV domes were cut are reinstalled for the units.

Commitment **#35.C**: Continue volumetric examinations where the SCV domes were cut at the frequency of once every five years until the coatings are reinstalled at these locations."

RAI 4.3.1-8a

Background:

In its September 30, 2013, response to RAI 4.3.1-8, the applicant stated that the pressurizer surge nozzle-to-safe end welds for the units were originally included in the cumulative usage factor (CUF) analyses for the pressurizer surge nozzles; however, the applicant stated that the design of the welds has been modified to include a full structural weld overlay (SWOL). The applicant also stated that, as identified in LRA Section 4.3.1.3, the current design basis of the pressurizer surge nozzles and their nozzle-to-safe end weld relies on a flaw evaluation that is used to establish the inservice inspection (ISI) frequency for the components.

Issue:

The response to RAI 4.3.1-8 may be inconsistent with LRA Section 4.3.1.3 Specifically, LRA Section 4.3.1.3, identifies that the flaw evaluation for the nickel alloy pressurizer surge nozzle-to-safe end weld was performed to assess postulated cracking that could be initiated and grown by a stress corrosion cracking (SCC) mechanism, and not by a metal fatigue mechanism. As a result, the response to RAI 4.3.1-8 will only provide a valid basis for concluding that the welds would not need to be evaluated for environmentally-assisted fatigue if it is demonstrated that the flaw evaluation of the pressurizer surge nozzle-to-safe end welds also included an evaluation of crack initiation and growth that is induced by a thermally-induced metal fatigue mechanism.

Thus, it is not evident whether flaw growth by a thermally-induced metal fatigue mechanism was included as part of the basis for establishing the inspection frequency that is used to schedule the inspections of the pressurizer spray nozzle-to-safe end weld under the applicant's ISI Program or Nickel Alloy Inspection Program.

Request:

Identify whether the flaw evaluation that was performed on the SWOL-modified pressurizer surge nozzle designs included an assessment of cracking that would be induced and grown by a thermally-induced metal fatigue mechanism (i.e., in addition to an assessment of cracking that is initiated and grown by SCC).

1. *If it is determined that the flaw evaluation did include an assessment of both SCC and fatigue, identify the inspection frequency that is currently applicable to the ISI inspections under the applicant's ISI Program or Nickel Alloy Inspection Program. In addition, identify which of the cracking mechanisms was determined to be limiting for establishment of the inspection frequency.*

2. *If it is determined that the flaw growth analysis does not include an assessment of cracking that could be initiated and grown by fatigue, identify design basis CUF values that are applicable to the pressurizer surge nozzle-to-safe end weld locations for Units 1 and 2 and justify why the CUF values for these Nickel alloy nozzle-to-safe end weld would not need to be adjusted for environmentally-assisted fatigue, as performed in accordance with the recommended guidance for performing environmentally-assisted fatigue analyses for Nickel alloy components in SRP-LR Section 4.3. Justify your responses to this request.*

TVA Response to RAI 4.3.1-8a:

The evaluation that was performed for the pressurizer surge nozzle SWOL considered the effects of thermally induced metal fatigue and the potential for stress corrosion cracking. The SWOL places compressive load on the original weld that reduces the potential for stress corrosion cracking in the original weld. The weld overlay material, Alloy 52/52M, is a nickel-based alloy that is highly resistant to stress corrosion cracking. If a flaw were to extend beyond the portion of the nozzle wall with compressive stresses and has a crack tip stress intensity that exceeded the value for PWSCC growth in the 82/182 material, then PWSCC could cause the crack to grow until the weld overlay material (52/52M) is reached. From that time on, fatigue crack growth could cause the crack to grow into the weld overlay material.

1. The evaluation of cracking of the original material identifies that PWSCC is possible if a flaw is large enough to cause the remaining area to exceed 10 KSI of tensile stress after application of operating pressure and loads. The analysis of the overlay material considers crack growth rate due to fatigue. The analysis determined that even with a postulated crack of 80% thru the original wall thickness, the remaining life would still be approximately 39 years for an axial flaw and 31 years for a radial flaw. The surge nozzle weld overlay inspection frequency for SQN units 1 and 2 is once every fourth refueling outage.

2. The full structural weld overlay analysis at the nickel alloy nozzle-to-safe end weld location is a flaw growth analysis that includes consideration of PWSCC and crack growth due to fatigue. Because there is no design basis fatigue analysis that determined a CUF for the nickel alloy nozzle-to-safe end weld, adjustment for environmentally assisted fatigue is not necessary at this location

ENCLOSURE 2

Tennessee Valley Authority
Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

Regulatory Commitment List, Revision 11

Commitments **6.D & F**, **9.C,G** to **M**, **24.B**, **35.B & C**, and **38** have been revised with additions underlined and deletions lined through.

This Commitment Revision supersedes all previous versions. The latest revision will be included in the LRA Appendix A, before the SQN LRA SER is issued.

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
1	Implement the **Aboveground Metallic Tanks** Program as described in LRA Section B.1.1	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.1
2	A. Revise **Bolting Integrity Program** procedures to ensure the actual yield strength of replacement or newly procured bolts will be less than 150 ksi B. Revise Bolting Integrity Program procedures to include the additional guidance and recommendations of EPRI NP-5769 for replacement of ASME pressure-retaining bolts and the guidance provided in EPRI TR-104213 for the replacement of other pressure-retaining bolts. C. Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer tube isolation valve flange bolts. D. Revise Bolting Integrity Program procedures to visually inspect a representative sample of normally submerged ERCW system bolts at least once every 5 years. (See Set 10 (30-day), Enclosure 1, B.1.2-2a)	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.2
3	A. Implement the **Buried and Underground Piping and Tanks Inspection Program** as described in LRA Section B.1.4. B. Cathodic protection will be provided based on the guidance of NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.4

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
4	A. Revise **Compressed Air Monitoring Program** procedures to include the standby diesel generator (DG) starting air subsystem. B. Revise Compressed Air Monitoring Program procedures to include maintaining moisture and other contaminants below specified limits in the standby DG starting air subsystem. C. Revise Compressed Air Monitoring Program procedures to apply a consideration of the guidance of ASME OM-S/G-1998, Part 17; EPRI NP-7079; and EPRI TR-108147 to the limits specified for the air system contaminants D. Revise Compressed Air Monitoring Program procedures to maintain moisture, particulate size, and particulate quantity below acceptable limits in the standby DG starting air subsystem to mitigate loss of material. E. Revise Compressed Air Monitoring Program procedures to include periodic and opportunistic visual inspections of surface conditions consistent with frequencies described in ASME O/M-SG-1998, Part 17 of accessible internal surfaces such as compressors, dryers, after-coolers, and filter boxes of the following compressed air systems: • Diesel starting air subsystem • Auxiliary controlled air subsystem • Nonsafety-related controlled air subsystem F. Revise Compressed Air Monitoring Program procedures to monitor and trend moisture content in the standby DG starting air subsystem. G. Revise Compressed Air Monitoring Program procedures to include consideration of the guidance for acceptance criteria in ASME OM-S/G-1998, Part 17, EPRI NP-7079; and EPRI TR-108147.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.5

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
5	A. Revise **Diesel Fuel Monitoring Program** procedures to monitor and trend sediment and particulates in the standby DG day tanks. B. Revise Diesel Fuel Monitoring Program procedures to monitor and trend levels of microbiological organisms in the seven-day storage tanks. C. Revise Diesel Fuel Monitoring Program procedures to include a ten-year periodic cleaning and internal visual inspection of the standby DG diesel fuel oil day tanks and high pressure fire protection (HPFP) diesel fuel oil storage tank. These cleanings and internal inspections will be performed at least once during the ten-year period prior to the period of extended operation (PEO) and at succeeding ten-year intervals. If visual inspection is not possible, a volumetric inspection will be performed. D. Revise Diesel Fuel Monitoring Program procedures to include a volumetric examination of affected areas of the diesel fuel oil tanks, if evidence of degradation is observed during visual inspection. The scope of this enhancement includes the standby DG seven-day fuel oil storage tanks, standby DG fuel oil day tanks, and HPFP diesel fuel oil storage tank and is applicable to the inspections performed during the ten-year period prior to the PEO and succeeding ten-year intervals.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.8
6	A. Revise **External Surfaces Monitoring Program** procedures to clarify that periodic inspections of systems in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(1) and (a)(3) will be performed. Inspections shall include areas surrounding the subject systems to identify hazards to those systems. Inspections of nearby systems that could impact the subject systems will include SSCs that are in scope and subject to aging management review for license renewal in accordance with 10 CFR 54.4(a)(2). B. Revise External Surfaces Monitoring Program procedures to include instructions to look for the following related to metallic components: • Corrosion and material wastage (loss of material). • Leakage from or onto external surfaces loss of material). • Worn, flaking, or oxide-coated surfaces (loss of material). • Corrosion stains on thermal insulation (loss of material). • Protective coating degradation (cracking, flaking, and blistering). • Leakage for detection of cracks on the external surfaces of stainless steel components exposed to an air environment containing halides. C. Revise External Surfaces Monitoring Program procedures to include instructions for monitoring aging effects for flexible polymeric components, including manual or physical manipulations of the material, with a sample size for manipulation of at least ten	6.A,B,C,E: SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.10

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(6)	percent of the available surface area. The inspection parameters for polymers shall include the following: • Surface cracking, crazing, scuffing, dimensional changes (e.g., ballooning and necking) -). • Discoloration. • Exposure of internal reinforcement for reinforced elastomers (loss of material). • Hardening as evidenced by loss of suppleness during manipulation where the component and material can be manipulated. D. ~~Revise External Surfaces Monitoring Program procedures to ensure surfaces that are insulated will be inspected when the external surface is exposed (i.e., during maintenance) at such intervals that would ensure that the components' intended function is maintained~~. Revise External Surfaces Monitoring Program procedures to specify the following for insulated components. • Periodic representative inspections are conducted during each 10-year period beginning 5 years before the PEO. • For a representative sample of outdoor components, except tanks, and indoor components, except tanks, identified with more than nominal degradation on the exterior of the component, insulation is removed for visual inspection of the component surface. Inspections include a minimum of 20 percent of the in-scope piping length for each material type (e.g., steel, stainless steel, copper alloy, aluminum). 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 is inspected. Inspected components are 20% of the population of each material type with a maximum of 25. Alternatively, insulation is removed and component inspections performed for any combination of a minimum of 25 1-foot axial length sections and individual components for each material type (e.g., steel, stainless steel, copper alloy, aluminum.) • For a representative sample of indoor components, except tanks, operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface or jacketing is inspected. These visual inspections verify that the jacketing and insulation is in good condition. The number of representative jacketing inspections will be at least 50 during each 10-year period. If the inspection determines there are gaps in the insulation or damage to the jacketing that would allow moisture to get behind the insulation, then removal of the insulation is required to inspect the component surface for degradation. • For a representative sample of indoor insulated tanks operated below the dew point and all insulated outdoor tanks, insulation is removed from either 25 1-square foot sections or 20 percent of the surface area for inspections of the exterior surface of each tank. The sample inspection points are distributed so that	6.D: SQN1: Prior to 09/17/15 SQN2: Prior to 09/15/16	

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM

(6)	inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (for example on top of stiffening rings).
	• Inspection locations are 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.
	• If tightly adhering insulation is installed, this insulation should be impermeable to moisture and there should be no evidence of damage to the moisture barrier. Given that the likelihood of CUI is low for tightly adhering insulation, a minimal number of inspections of the external moisture barrier of this type of insulation, although not zero, will be credited toward the sample population.
	• 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
	  • No evidence of cracking
	Nominal degradation is defined as 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. [RAI 3.0.3-1 Request 6]
	
	E. Revise External Surfaces Monitoring Program procedures to include acceptance criteria. Examples include the following:
	• Stainless steel should have a clean shiny surface with no discoloration.
	• Other metals should not have any abnormal surface indications.
	• Flexible polymers should have a uniform surface texture and color with no cracks and no unanticipated dimensional change, no abnormal surface with the material in an as-new condition with respect to hardness, flexibility, physical dimensions, and color.
	• Rigid polymers should have no erosion, cracking, checking or chalks.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(6)	F. For a representative sample of outdoor insulated components and indoor insulated components operated below the dew point, which have been identified with more than nominal degradation on the exterior of the component, insulation is removed for inspection of the component surface. For a representative sample of indoor insulated components operated below the dew point, which have not been identified with more than nominal degradation on the exterior of the component, the insulation exterior surface is inspected. These inspections will be conducted during each 10-year period beginning **5** years before the PEO. [RAI 3.0.3-1 Request 6]	6.F: SQN1: Prior to 09/17/15 SQN2: Prior to 09/15/16	
7	A. Revise **Fatigue Monitoring Program** procedures to monitor and track critical thermal and pressure transients for components that have been identified to have a fatigue Time Limited Aging Analysis. B. Fatigue usage calculations that consider the effects of the reactor water environment will be developed for a set of sample reactor coolant system (RCS) components. This sample set will include the locations identified in NUREG/CR-6260 and additional plant-specific component locations in the reactor coolant pressure boundary if they are found to be more limiting than those considered in NUREG/CR-6260. In addition, fatigue usage calculations for reactor vessel internals (lower core plate and control rod drive (CRD) guide tube pins) will be evaluated for the effects of the reactor water environment. F_{en} factors will be determined as described in Section 4.3.3. C. Fatigue usage factors for the RCS pressure boundary components will be adjusted as necessary-to incorporate the effects of the Cold Overpressure Mitigation System (COMS) event (i.e., low temperature overpressurization event) and the effects of structural weld overlays. D. Revise Fatigue Monitoring Program procedures to provide updates of the fatigue usage calculations and cycle-based fatigue waiver evaluations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components have been modified. E. Revise Fatigue Monitoring Program procedures to track the tensioning cycles for the reactor coolant pump hydraulic studs.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.11

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
8	A. Revise **Fire Protection Program** procedures to include an inspection of fire barrier walls, ceilings, and floors for any signs of degradation such as cracking, spalling, or loss of material caused by freeze thaw, chemical attack, or reaction with aggregates. B. Revise Fire Protection Program procedures to provide acceptance criteria of no significant indications of concrete cracking, spalling, and loss of material of fire barrier walls, ceilings, and floors and in other fire barrier materials.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.12
9	Implement the **Fire Water System Program** as described in LRA Section B.1.13. A. Revise Fire Water System Program procedures to include periodic visual inspection of fire water system internals for evidence of corrosion and loss of wall thickness. B. Revise Fire Water System Program procedures to include one of the following options: • 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 PEO 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. • A visual inspection of the internal surface of fire protection piping will be performed upon each entry into the system for routine or corrective maintenance. These inspections will be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) 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 PEO. 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 be performed as needed to obtain this representative sample prior to the PEO and periodically during the PEO based on the findings from the inspections performed prior to the PEO. C. Revise Fire Water System Program procedures to ensure a sprinkler heads are tested in accordance with NFPA-25 (2011 Edition), Section 5.3.1 [RAI 3.0.3-1 Request 4] ~~Revise Fire Water System Program procedures to ensure a representative sample of sprinkler heads will be tested or replaced before the end of the 50-year sprinkler head service life and at ten-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 four sprinklers or one percent of the number of sprinklers per individual sprinkler sample, whichever is greater. If the option to replace the sprinklers is chosen, all sprinkler heads that have been in service for 50 years will be replaced.~~	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.13

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	D. Revise the Fire Water System Program full flow testing to be in accordance with full flow testing standards of NFPA-25 (2011). E. Revise Fire Water System Program procedures to include acceptance criteria for periodic visual inspection of fire water system internals for corrosion, minimum wall thickness, and the absence of biofouling in the sprinkler system that could cause corrosion in the sprinklers. F. Prior to the PEO, SQN 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 for high pressure fire protection system 26 and essential raw cooling water system 67. [RAI 3.0.3-1, request 5a, Set 10.30, 9/3/13] G. Revise Fire Water System Program procedures to periodically remove a representative sample of components such as sprinkler heads or couplings prior to the PEO and perform a visual internal inspection of dry fire water system piping for evidence of corrosion, loss of wall thickness, and foreign material that may result in flow blockage using the methodology described in NFPA-25 Section 14.2.1. This includes those sections of dry piping described in NRC Information Notice (IN) 2013-06, where drainage is not occurring. The acceptance criteria shall be "no debris" (i.e., no corrosion products that could impede flow or cause downstream components to become clogged). Any additional inspections in accordance with NFPA-25, Sections 14.2.1 or 14.2.2 will be based on the initial inspection results. H. Revise Fire Water System Program procedures to perform an obstruction evaluation in accordance with NFPA-25 (2011 Edition), Section 14.3.1. I. Revise Fire Water System Program procedures to conduct follow-up volumetric examinations if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness. J. Revise Fire Water System Program procedures to annually inspect the fire water storage tank exterior painted surface for signs of degradation. If degradation is identified, conduct follow-up volumetric examinations to ensure wall thickness is equal to or exceeds nominal wall thickness. The fire water storage tanks will be inspected in accordance with NFPA-25 (2011 Edition) requirements. K. Revise Fire Water System Program procedures to include a fire water storage tank interior inspection every five years that includes inspections for signs of pitting, spalling, rot, waste material and debris, and aquatic growth. Include in the revision direction to		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	perform fire water storage tank interior coating testing, if any degradation is identified, in accordance with ASTM D 3359 or equivalent, a dry film thickness test at random locations to determine overall coating thickness; and a wet sponge test to detect pinholes, cracks or other compromises of the coating. If there is evidence of pitting or corrosion ensure the Fire Water System Program procedures direct performance of an examination to determine wall and bottom thickness. L. Revise Fire Water System Program procedures based on the results of a feasibility study to perform the main drain tests in accordance with NFPA-25 (2011 Edition) Section 13.2.5. M. Revise Fire Water System Program procedures to perform spray head discharge pattern tests from all open spray nozzles to ensure that patterns are not impeded by plugged nozzles, to ensure that nozzles are correctly positioned, and to ensure that obstructions do not prevent discharge patterns from wetting surfaces to be protected. Where the nature of the protected property is such that water cannot be discharged, the nozzles shall be inspected for proper orientation and the system tested with smoke or some other medium to ensure that the nozzles are not obstructed. [RAI 3.0.3-1, Request 4, for Commitments 9.C,G to M]		
10	A. Revise **Flow Accelerated Corrosion** (FAC) **Program** procedures to implement NSAC-202L guidance for examination of components upstream of piping surfaces where significant wear is detected. B. Revise FAC Program procedures to implement the guidance in LR-ISG-2012-01, which will include a susceptibility review based on internal operating experience, external operating experience, EPRI TR-1011231, *Recommendations for Controlling Cavitation, Flashing, Liquid Droplet Impingement, and Solid Particle Erosion in Nuclear Power Plant Piping*, and NUREG/CR-6031, *Cavitation Guide for Control Valves*.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.14
11	Revise **Flux Thimble Tube Inspection Program** procedures to include a requirement to address if the predictive trending projects that a tube will exceed 80% wall wear prior to the next planned inspection, then initiate a Service Request (SR) to define actions (i.e., plugging, repositioning, replacement, evaluations, etc.) required to ensure that the projected wall wear does not exceed 80%. If any tube is found to be >80% through wall wear, then initiate a Service Request (SR) to evaluate the predictive methodology used and modify as required to define corrective actions (i.e., plugging, repositioning, replacement, etc).	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.15

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
12	A. Revise **Inservice Inspection–IWF Program** procedures to clarify that detection of aging effects will include monitoring anchor bolts for loss of material, loose or missing nuts, and cracking of concrete around the anchor bolts. B. Revise ISI - IWF Program procedures to include the following corrective action guidance. When a component support is found with minor age-related degradation, but still is evaluated as "acceptable for continued service" as defined in IWF-3400, the program owner may choose to repair the degraded component. If the component is repaired, the program owner will substitute a randomly selected component that is more representative of the general population for subsequent inspections.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.17
13	Inspection of **Overhead Heavy Load and Light Load** (Related to Refueling) **Handling Systems**: A. Revise program procedures to specify the inspection scope will include monitoring of rails in the rail system for wear; monitoring structural components of the bridge, trolley and hoists for the aging effect of deformation, cracking, and loss of material due to corrosion; and monitoring structural connections/bolting for loose or missing bolts, nuts, pins or rivets and any other conditions indicative of loss of bolting integrity. B. Revise program procedures to include the inspection and inspection frequency requirements of ASME B30.2. C. Revise program procedures to clarify that the acceptance criteria will include requirements for evaluation in accordance with ASME B30.2 of significant loss of material for structural components and structural bolts and significant wear of rail in the rail system. D. Revise program procedures to clarify that the acceptance criteria and maintenance and repair activities use the guidance provided in ASME B30.2	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.18
14	Implement the **Internal Surfaces in Miscellaneous Piping and Ducting Components Program** as described in LRA Section B.1.19.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.19
15	Implement the **Metal Enclosed Bus Inspection Program** as described in LRA Section B.1.21.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.21
16	A. Revise **Neutron Absorbing Material Monitoring Program** procedures to perform blackness testing of the Boral coupons within the ten years prior to the PEO and at least every ten years thereafter based on initial testing to determine possible changes in boron-10 areal density.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.22

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(16)	B. Revise Neutron Absorbing Material Monitoring Program procedures to relate physical measurements of Boral coupons to the need to perform additional testing. C. Revise Neutron Absorbing Material Monitoring Program procedures to perform trending of coupon testing results to determine the rate of degradation and to take action as needed to maintain the intended function of the Boral.		
17	Implement the **Non-EQ Cable Connections Program** as described in LRA Section B.1.24	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.24
18	Implement the **Non-EQ Inaccessible Power Cable** (400 V to 35 kV) **Program** as described in LRA Section B.1.25 A. TVA response to **RAI B.1.25.1a** 1. Repair the manhole sump pump and discharge piping deficiencies associated with the accumulation of water in seven manholes/handholes that are scheduled for correction and/or mitigation by September 2015. (HH3, HH2B, HH52B, HH55A2, MH7B, MH10A and MH32B as identified on October 1, 2013) 2. Grade the ground surface around Manhole 31 to direct runoff away from the manhole. The re-grading is scheduled for completion by September 2014. 3. Prior to the PEO, the license renewal commitment for the Non-EQ Inaccessible Power Cables (400 V to 35 kV) Program will establish diagnostic testing activities on all inaccessible power cables in the 400 V to 35kV range that are in the scope of license renewal and subject to aging management review. 4. Revise the manhole inspection procedures to specify the maximum allowable water level to preclude cable submergence in the manhole. If the inspection identifies submergence of inaccessible power cable for more than a few days, the condition will be documented and evaluated in the SQN corrective action program. The evaluation will consider results of the most recent diagnostic testing, insulation type, submergence level, voltage level, energization cycle (usage), and various other inputs to determine whether the cables remain capable of performing their intended current licensing basis function.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21 18.A.1: Sept 2015 18.A2 & 4: Sept 2014 18.A.3: SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.25
19	Implement the **Non-EQ Instrumentation Circuits Test Review Program** as described in LRA Section B.1.26.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.26
20	Implement the **Non-EQ Insulated Cables and Connections Program** as described in LRA Section B.1.27	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.27

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
21	A. Revise **Oil Analysis Program** procedures to monitor and maintain contaminants in the 161-kV oil filled cable system within acceptable limits through periodic sampling in accordance with industry standards, manufacturer's recommendations and plant-specific operating experience. B. Revise Oil Analysis Program procedures to trend oil contaminant levels and initiate a problem evaluation report if contaminants exceed alert levels or limits in the 161-kV oil-filled cable system.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.28
22	Implement the **One-Time Inspection Program** as described in LRA Section B.1.29.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.29
23	Implement the **One-Time Inspection – Small Bore Piping Program** as described in LRA Section B.1.30	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.30
24	A. Revise **Periodic Surveillance and Preventive Maintenance Program** procedures as necessary to include all activities described in the table provided in the LRA Section B.1.31 program description. B. RAI 3.0.3-1, Request 3, Loss of Coating Integrity: For in-scope components that have internal Service Level III or Other coatings, initial inspections will begin no later than the last scheduled refueling outage prior to the period of extended operation (PEO). Subsequent inspections will be performed based on the initial inspection results.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21 24.B SQN1: RFO Prior to 09/17/20 SQN2: RFO Prior to 09/15/21	B.1.31
25	A. Revise **Protective Coating Program** procedures to clarify that detection of aging effects will include inspection of coatings near sumps or screens associated with the emergency core cooling system. B. Revise Protective Coating Program procedures to clarify that instruments and equipment needed for inspection may include, but not be limited to, flashlights, spotlights, marker pen, mirror, measuring tape, magnifier, binoculars, camera with or without wide-angle lens, and self-sealing polyethylene sample bags. C. Revise Protective Coating Program procedures to clarify that the last two performance monitoring reports pertaining to the coating systems will be reviewed prior to the inspection or monitoring process.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.32
26	A. Revise **Reactor Head Closure Studs Program** procedures to ensure that replacement studs are fabricated from bolting material with actual measured yield strength less than 150 ksi. B. Revise Reactor Head Closure Studs Program procedures to exclude the use of molybdenum disulfide (MoS_2) on the reactor vessel closure studs and to refer to Reg. Guide 1.65, Rev1.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.33

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
27	A. Revise **Reactor Vessel Internals Program** procedures to take physical measurements of the Type 304 stainless steel hold-down springs in Unit 1 at each refueling outage to ensure preload is adequate for continued operation. B. Revise Reactor Vessel Internals Program procedures to include preload acceptance criteria for the Type 304 stainless steel hold-down springs in Unit 1.	SQN1: Prior to 09/17/20 SQN2: Not Applicable	B.1.34
28	A. Revise **Reactor Vessel Surveillance Program** procedures to consider the area outside the beltline such as nozzles, penetrations and discontinuities to determine if more restrictive pressure-temperature limits are required than would be determined by just considering the reactor vessel beltline materials. B. Revise Reactor Vessel Surveillance Program procedures to incorporate an NRC-approved schedule for capsule withdrawals to meet ASTM-E185-82 requirements, including the possibility of operation beyond 60 years (refer to the TVA Letter to NRC, "Sequoyah Reactor Pressure Vessel Surveillance Capsule Withdrawal Schedule Revision Due to License Renewal Amendment," dated January 10, 2013, ML13032A251.) C. Revise Reactor Vessel Surveillance Program procedures to withdraw and test a standby capsule to cover the peak fluence expected at the end of the PEO.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.35
29	Implement the **Selective Leaching Program** as described in LRA Section B.1.37.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.37
30	Revise **Steam Generator Integrity Program** procedures to ensure that corrosion resistant materials are used for replacement steam generator tube plugs.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.39
31	A. Revise **Structures Monitoring Program** procedures to include the following in-scope structures: • Carbon dioxide building • Condensate storage tanks' (CSTs) foundations and pipe trench • East steam valve room Units 1 & 2 • Essential raw cooling water (ERCW) pumping station • High pressure fire protection (HPFP) pump house and water storage tanks' foundations • Radiation monitoring station (or particulate iodine and noble gas station) Units 1 & 2 • Service building • Skimmer wall (Cell No. 12) • Transformer and switchyard support structures and foundations B. Revise Structures Monitoring Program procedures to specify the following list of in-scope structures are included in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.40

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	Power Plants Program (Section B.1.36): • Condenser cooling water (CCW) pumping station (also known as intake pumping station) and retaining walls • CCW pumping station intake channel • ERCW discharge box • ERCW protective dike • ERCW pumping station and access cells • Skimmer wall, skimmer wall Dike A and underwater dam C. Revise Structures Monitoring Program procedures to include the following in-scope structural components and commodities: • Anchor bolts • Anchorage/embedments (e.g., plates, channels, unistrut, angles, other structural shapes) • Beams, columns and base plates (steel) • Beams, columns, floor slabs and interior walls (concrete) • Beams, columns, floor slabs and interior walls (reactor cavity and primary shield walls; pressurizer and reactor coolant pump compartments; refueling canal, steam generator compartments; crane wall and missile shield slabs and barriers) • Building concrete at locations of expansion and grouted anchors; grout pads for support base plates • Cable tray • Cable tunnel • Canal gate bulkhead • Compressible joints and seals • Concrete cover for the rock walls of approach channel • Concrete shield blocks • Conduit • Control rod drive missile shield • Control room ceiling support system • Curbs • Discharge box and foundation • Doors (including air locks and bulkhead doors) • Duct banks • Earthen embankment • Equipment pads/foundations • Explosion bolts (E. G. Smith aluminum bolts) • Exterior above and below grade; foundation (concrete) • Exterior concrete slabs (missile barrier) and concrete caps • Exterior walls: above and below grade (concrete) • Foundations: building, electrical components, switchyard, transformers, circuit breakers, tanks, etc. • Ice baskets • Ice baskets lattice support frames • Ice condenser support floor (concrete) • Insulation (fiberglass, calcium silicate) • Intermediate deck and top deck of ice condenser • Kick plates and curbs (steel - inside steel containment vessel)		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• Lower inlet doors (inside steel containment vessel) • Lower support structure structural steel: beams, columns, plates (inside steel containment vessel) • Manholes and handholes • Manways, hatches, manhole covers, and hatch covers (concrete) • Manways, hatches, manhole covers, and hatch covers (steel) • Masonry walls • Metal siding • Miscellaneous steel (decking, grating, handrails, ladders, platforms, enclosure plates, stairs, vents and louvers, framing steel, etc.) • Missile barriers/shields (concrete) • Missile barriers/shields (steel) • Monorails • Penetration seals • Penetration seals (steel end caps) • Penetration sleeves (mechanical and electrical not penetrating primary containment boundary) • Personnel access doors, equipment access floor hatch and escape hatches • Piles • Pipe tunnel • Precast bulkheads • Pressure relief or blowout panels • Racks, panels, cabinets and enclosures for electrical equipment and instrumentation • Riprap • Rock embankment • Roof or floor decking • Roof membranes • Roof slabs • RWST rainwater diversion skirt • RWST storage basin • Seals and gaskets (doors, manways and hatches) • Seismic/expansion joint • Shield building concrete foundation, wall, tension ring beam and dome: interior, exterior above and below grade • Steel liner plate • Steel sheet piles • Structural bolting • Sumps (concrete) • Sumps (steel) • Sump liners (steel) • Sump screens • Support members; welds; bolted connections; support anchorages to building structure (e.g., non-ASME piping and components supports, conduit supports, cable tray supports, HVAC duct supports, instrument tubing supports, tube track		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	supports, pipe whip restraints, jet impingement shields, masonry walls, racks, panels, cabinets and enclosures for electrical equipment and instrumentation) • Support pedestals (concrete) • Transmission, angle and pull-off towers • Trash racks • Trash racks associated structural support framing • Traveling screen casing and associated structural support framing • Trenches (concrete) • Tube track • Turning vanes • Vibration isolators D. Revise Structures Monitoring Program procedures to include periodic sampling and chemical analysis of ground water chemistry for pH, chlorides, and sulfates on a frequency of at least every five years. E. Revise Masonry Wall Program procedures to specify masonry walls located in the following in-scope structures are in the scope of the Masonry Wall Program: • Auxiliary building • Reactor building Units 1 & 2 • Control bay • ERCW pumping station • HPFP pump house • Turbine building F. Revise Structures Monitoring Program procedures to include the following parameters to be monitored or inspected: • Requirements for concrete structures based on ACI 349-3R and ASCE 11 and include monitoring the surface condition for loss of material, loss of bond, increase in porosity and permeability, loss of strength, and reduction in concrete anchor capacity due to local concrete degradation. • Loose or missing nuts for structural bolting. • Monitoring gaps between the structural steel supports and masonry walls that could potentially affect wall qualification. G. Revise Structures Monitoring Program procedures to include the following components to be monitored for the associated parameters: • Anchors/fasteners (nuts and bolts) will be monitored for loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts. • Elastomeric vibration isolators and structural sealants will be monitored for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening). • Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	H. Revise Structures Monitoring Program procedures to include the following for detection of aging effects: • Inspection of structural bolting for loose or missing nuts. • Inspection of anchor bolts for loose or missing nuts and/or bolts, and cracking of concrete around the anchor bolts. • Inspection of elastomeric material for cracking, loss of material, loss of sealing, and change in material properties (e.g., hardening), and supplement inspection by feel or touch to detect hardening if the intended function of the elastomeric material is suspect. Include instructions to augment the visual examination of elastomeric material with physical manipulation of at least ten percent of available surface area. • Opportunistic inspections when normally inaccessible areas (e.g., high radiation areas, below grade concrete walls or foundations, buried or submerged structures) become accessible due to required plant activities. Additionally, inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring. • Inspection of submerged structures at least once every five years. Inspections of water control structures should be conducted under the direction of qualified personnel experienced in the investigation, design, construction, and operation of these types of facilities. • Inspections of water control structures shall be performed on an interval not to exceed five years. • Perform special inspections of water control structures immediately (within 30 days) following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls. • Insulation (fiberglass, calcium silicate) will be monitored for loss of material and change in material properties due to potential exposure to moisture that can cause loss of insulation effectiveness. I. Revise Structures Monitoring Program procedures to prescribe quantitative acceptance criteria ~~is~~ based on the quantitative acceptance criteria of ACI 349.3R and information provided in industry codes, standards, and guidelines including ACI 318, ANSI/ASCE 11 and relevant AISC specifications. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria. J. Revise Structures Monitoring Program procedures to clarify that detection of aging effects will include the following. Qualifications of personnel conducting the inspections or testing and evaluation of structures and structural components meet the guidance in Chapter 7 of ACI 349.3R.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	K. Revise Structures Monitoring Program procedures to include the following acceptance criteria for insulation (calcium silicate and fiberglass) • No moisture or surface irregularities that indicate exposure to moisture. L. Revise Structures Monitoring Program procedures to include the following preventive actions. Specify protected storage requirements for high-strength fastener components (specifically ASTM A325 and A490 bolting). Storage of these fastener components shall include: 1. Maintaining fastener components in closed containers to protect from dirt and corrosion; 2. Storage of the closed containers in a protected shelter; 3. Removal of fastener components from protected storage only as necessary; and 4. Prompt return of any unused fastener components to protected storage. M. TVA Response to RAI **B.1.40-4a** (Turbine Building wall crack) 1. SQN will map and trend the crack in the condenser pit north wall. 2. SQN will test water inleakage samples from the turbine building condenser pit walls and floor slab for minerals and iron content to assess the effect of the water inleakage on the concrete and the reinforcing steel. 3. SQN will test concrete core samples removed from the turbine building condenser pit north wall with a minimum of one core sample in the area of the crack. The core samples will be tested for compressive strength and modulus of elasticity and subjected to petrographic examination. 4. The results of the tests and SMP inspections will be used to determine further corrective actions, if necessary. 5. Commitment #31.M will be implemented before the PEO for SQN Units 1 and 2.		
32	Implement the **Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)** as described in LRA Section B.1.41	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.41
33	A. Revise **Water Chemistry Control - Closed Treated Water Systems Program** procedures to provide a corrosion inhibitor for the following chilled water subsystems in accordance with industry guidelines and vendor recommendations: • Auxiliary building cooling • Incore Chiller 1A, 1B, 2A, & 2B • 6.9 kV Shutdown Board Room A & B B. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to conduct inspections whenever a boundary is opened for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(33)	• High pressure fire protection diesel jacket water system • Chilled water portion of miscellaneous HVAC systems (i.e., auxiliary building, Incore Chiller 1A, 1B, 2A, & 2B, and 6.9 kV Shutdown Board Room A & B) C. Revise Water Chemistry Control-Closed Treated Water Systems Program procedures to state these inspections will be conducted in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that are capable of detecting corrosion or cracking. D. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to perform sampling and analysis of the glycol cooling system per industry standards and in no case greater than quarterly unless justified with an additional analysis. E. Revise Water Chemistry Control - Closed Treated Water Systems Program procedures to inspect a representative sample of piping and components at a frequency of once every ten years for the following systems: • Standby diesel generator jacket water subsystem • Component cooling system • Glycol cooling loop system • High pressure fire protection diesel jacket water system • Chilled water portion of miscellaneous HVAC systems (i.e., auxiliary building, Incore Chiller 1A, 1B, 2A, & 2B, and 6.9 kV Shutdown Board Room A & B) F. Components inspected will be those with the highest likelihood of corrosion or cracking. 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. These inspections will be in accordance with applicable ASME Code requirements, industry standards, or other plant-specific inspection and personnel qualification procedures that ensure the capability of detecting corrosion or cracking.		
34	Revise **Containment Leak Rate Program** procedures to require venting the SCV bottom liner plate weld leak test channels to the containment atmosphere prior to the CILRT and resealing the vent path after the CILRT to prevent moisture intrusion during plant operation.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.7

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
35	A. From B.1.6-1 Response: Modify the configuration of the SQN Unit 1 test connection access boxes to prevent moisture intrusion to the leak test channels. Prior to installing this modification, TVA will perform remote visual examinations inside the leak test channels by inserting a borescope video probe through the test connection tubing. B. From B.1.6-1b Response: To monitor the condition of the access boxes and associated materials, perform visual examinations of all accessible surfaces, including the access box surfaces, cover plate, welds, and gasket sealing surfaces of the access boxes on each unit every other refueling outage with the gasketed access box lid removed. [RAI B.1.6-1b] C. From B.1.6-2b Response: Continue volumetric examinations where the SCV domes were cut at the frequency of once every five years until the coatings are reinstalled at these locations. [RAI B.1.6-2b]	35.A: SQN1: Prior to 09/17/20 SQN2: Not Applicable 35. B & C: SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.6
36	Revise **Inservice Inspection Program** procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the materials selection criteria of NUREG-0313, Revision 2 with regard to ferrite and carbon content. An inspection techniques qualified by ASME or EPRI will be used to monitor cracking. Inspections will be conducted on a sampling basis. The extent of sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.16

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
37	TVA will implement the **Operating Experience** for the **AMPs** in accordance with the TVA response to the RAI B.0.4-1 on July 29, 2013 letter to the NRC. (See Set 7.30day RAI B.0.4-1 Response, ML13213A027); and Oct 16, 2013 2013 letter to the NRC. (See Set 13.30d RAIs B.0.4-1a and A.1-1a Response) • Revise OE Program Procedure to include current and future revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," as a source of industry OE, and unanticipated age-related degradation or impacts to aging management activities as a screening attribute. • Revise the CAP Procedure to provide a screening process of corrective action documents for aging management items, the assignment of aging corrective actions to appropriate AMP owners, and consideration of the aging management trend code. • Revise AMP procedures as needed to provide for review and evaluation by AMP owners of data from inspections, tests, analyses or AMP OEs. • Revise the OE Program Procedure to provide guidance for reporting plant-specific OE on unanticipated age-related degradation or impact to aging management activities to the TVA fleet and/or INPO. • Revise the OE, CAP, Initial and Continuing Engineering Support Personnel Training to address age-related topics, the unanticipated degradation or impacts to the aging management activities; including periodic refresher/update training and provisions to accommodate the turnover of plant personnel, and recent AMP-related OE from INPO, the NRC, Scientech, and nuclear industry-initiated guidance documents and standards." • A comprehensive and holistic AMP training topic list will be developed before the date the SQN renewed operating license is scheduled to be issued. • TVA AMP OE Process, AMP adverse trending & evaluation in CAP, AMP Initial and Refresher Training will be fully implemented by the date the SQN renewed operating license is scheduled to be issued.	No later than the scheduled issue date of the renewed operating licenses for SQN Units 1 & 2. (Currently February 2015)	B.0.4
38	Implement the **Service Water Program** as described in LRA Section B.1.38. (RAI 3.0.3-1, Request 3)	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.38

The above table identifies the **38** SQN NRC LR commitments. Any other statements in this letter are provided for information purposes and are not considered to be regulatory commitments.

This Commitment Revision supersedes all previous versions.