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

September 3, 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, Set 10 (30-day), B.1.9-1, B.1.4-4 Revised RAI Responses, and Revision to LRA page 2.4-44 (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. ML 13204A257)
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, Set 4/Buried Piping, Set 8, and Set 9," dated July 25, 2013 (ADAMS Accession No. ML 13213A026)
4. 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, Set 7 (30-day)," dated July 29, 2013 (ADAMS Accession No. ML 13213A027)

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. The required date for responding to new RAI 3.0.3-1 (Requests 2 and 5), and follow-up RAIs 3.5.2.3.4-1a, B.1.41-3a, B.1.23-2a, and B.1.2-2a from Set 10 was within 30 days of the date stated in the RAI (i.e., no later than September 3, 2013, considering the weekend day and holiday). The NRC License Renewal Project Manager, Mr. Richard Plasse, has given a verbal extension for B.1.23-2a until October 1, 2013. Enclosure 1 to this letter provides TVA's response for Set 10 (30-day).

By References 3 and 4, TVA submitted responses that included RAIs B.1.4-4 and RAI B.1.9-1, respectively. In August 5 and August 16, 2013 telecoms, Mr. Plasse requested clarifications for these RAI responses. Enclosure 2 provides the requested clarifications. In addition, Enclosure 2 provides a correction to LRA page 2.4-44 that was requested in an August 14, 2013, email from Mr. Emmanuel Sayoc, an NRC reviewer.

Enclosure 3 is an updated list of the regulatory commitments for license renewal.

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 3rd day of September 2013.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures:
1. TVA Responses to NRC Request for Additional Information: Set 10 (30-day)
2. Revised Responses to RAI B.1.9-1a and B.1.4-4b, and revision to LRA page 2.4- 4
3. Regulatory Commitment List, Revision 6

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: Set 10 (30-day)

RAI 3.0.3-1 (Request #2)

Background:

Recent industry operating experience (OE) and questions raised during the staff's review of several license renewal applications (LRAs) has resulted in the staff concluding that several aging management programs (AMP) and aging management review (AMR) items in the LRA may not or do not account for this OE.

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

2. *A representative minimum sample size for periodic inspections for the Generic Aging Lessons Learned (GALL) Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program"*

Issue #2:

2. *A representative minimum sample size for periodic inspections for the GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Program"*

   GALL Report AMP XI.M38 recommends that inspections be performed during periodic system and component surveillances or during the performance of maintenance activities when the surfaces are made accessible for visual inspection. As stated in program element 4, "detection of aging effects," "[v]isual and mechanical inspections conducted under this program are opportunistic in nature; they are conducted whenever piping or ducting is opened for any reason." It is possible that opportunistic inspections may not be available for one or more material, environment, and aging effect combinations presented in the AMR line items where GALL Report AMP XI.M38 is referenced. With the exception of a few GALL Report AMR items where preventive actions alone are considered sufficient to manage aging effects, it is the staff's position that, to credit a GALL Report AMP for aging management, some assurance that a representative sample of all material, environment, and aging effect combinations will be inspected is necessary. The Periodic Surveillance and Preventive Maintenance Program provides for a periodic representative sample, whereas, the Internal Surfaces in Miscellaneous Piping and Ducting Components Program does not.

Request #2:

2. *A representative minimum sample size for periodic inspections in GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"*
   a. *State how LRA Sections A.1.19 and B.1.19 will be revised to ensure that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program conducts periodic inspections on a representative sample of in-scope components. Alternatively, state why no changes to the program are necessary to ensure that each applicable material, environment, and aging effect will be appropriately managed during the period of extended operation.*

TVA Response to RAI 3.0.3-1 (Request #2)

a. Changes to LRA Sections A.1.19 and B.1.19 to ensure that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program conducts periodic inspections on a representative samples of in-scope components if opportunistic inspections are not available for one or more material, environment, and aging effect combinations, are shown with additions underlined.

"LRA Section A.1.19

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program manages fouling, cracking, loss of material, and change in material properties using opportunistic visual inspections of the internal surfaces of piping and components during periodic surveillances or maintenance activities when the surfaces are accessible for visual inspection.

This opportunistic approach is supplemented with the following sampling approach.

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

For metallic components, visual inspection of surface conditions will be used to detect loss of material, fouling and cracking. For elastomeric components, visual inspections and physical manipulation will be used to detect cracking and change in material properties. The program monitors surface condition for visible evidence of loss of material in metallic components and changes in material properties for elastomeric components, including possible evidence of surface discontinuities. Visual examinations of elastomeric components are accompanied by

physical manipulation such that changes in material properties are readily observable. The sample size for physical manipulation is at least ten percent of available surface area, including visually identified suspect areas.

Specific acceptance criteria are as follows:

- Stainless steel: clean surfaces, shiny, no abnormal surface condition.
- Metals: no abnormal surface condition.
- Flexible polymers: a uniform surface texture and color with no cracks, no unanticipated dimensional change, and no abnormal surface conditions.
- Rigid polymers: no surface changes affecting performance such as erosion and cracking.

Conditions that do not meet the acceptance criteria are entered into the corrective action program for evaluation. Any indications of relevant degradation will be evaluated using design standards, procedural requirements, current licensing basis, and industry codes or standards.

This program will be implemented prior to the PEO.

LRA Section B.1.19

The Internal Surfaces in Miscellaneous Piping and Ducting Components Program is a new program that will manage fouling, cracking, loss of material, and change in material properties using opportunistic visual inspections of the internal surfaces of piping and components during periodic surveillances or maintenance activities when the surfaces are accessible for visual inspection.

<u>This opportunistic approach is supplemented with the following sampling approach.</u>

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

For metallic components, visual inspection of surface conditions will be used to detect loss of material, fouling and cracking. For elastomeric components, visual inspections and physical manipulation will be used to detect cracking and change in material properties. The program monitors surface condition for visible evidence of loss of material in metallic components and changes in material properties for elastomeric components, including possible evidence of

surface discontinuities. Visual examinations of elastomeric components are accompanied by physical manipulation such that changes in material properties are readily observable. The sample size for physical manipulation is at least ten percent of available surface area, including visually identified suspect areas.

Specific acceptance criteria are as follows:

- Stainless steel: clean surfaces, shiny, no abnormal surface condition.
- Metals: no abnormal surface condition.
- Flexible polymers: a uniform surface texture and color with no cracks, no unanticipated dimensional change, and no abnormal surface conditions.
- Rigid polymers: no surface changes affecting performance such as erosion and cracking.

Conditions that do not meet the acceptance criteria are entered into the corrective action program for evaluation. Any indications of relevant degradation will be evaluated using design standards, procedural requirements, current licensing basis, and industry codes or standards.

This program will be implemented prior to the PEO."

(See Commitment #14)

RAI 3.0.3-1 (Request #5)

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:

5. *Scope and inspection recommendations of GALL Report AMP XI.M29, "Aboveground Metallic Tanks"*

Issue #5:

5. Scope and inspection recommendations of GALL Report AMP XI.M29, "Aboveground Metallic Tanks"

There have been several instances of OE related to age-related degradation of tanks. Tanks with defects variously described as wall thinning, pinhole leaks, cracks, and through-wall flaws have been identified by detecting external leakage rather than through internal inspections. None of the leaks or degraded coatings has resulted in a loss of intended function; however, the number of identified conditions adverse to quality and the continued aging of the tanks indicate a need to ensure that internal tank inspections are conducted throughout the PEO. In addition, the staff identified an indoor tank with external SCC that, except for its location, would normally be in the scope of GALL Report AMP XI.M29. As such, in regard to the recommendations in GALL Report XI.M29, the staff position is as follows:

a. *Most water-filled indoor tanks are currently managed by GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," and GALL Report AMP XI.M38. Neither of these AMPs has a recommendation to conduct periodic volumetric examinations of the bottom of the tank or internal inspections. Based on industry OE, the staff believes that some indoor tanks should have internal inspections. These include indoor welded storage tanks that meet all of the following criteria:*
   i. *have a large volume (i.e., greater than 100,000 gallons)*
   ii. *are designed to near-atmospheric internal pressures*
   iii. *sit on concrete or soil*
   iv. *are exposed internally to water*

b. *Based on industry OE related to cracking due to SCC and fatigue, stainless steel and aluminum tanks should be inspected using surface examination techniques.*

c. *Based on the tank's material and environment, the attached Table 5a, "Tank Inspection Recommendations," contains the types of aging effects requiring management (AERM), inspection type, and frequency of inspections that should be conducted to provide*

reasonable assurance that the intended functions of the tank will be maintained consistent with the current licensing basis (CLB) for the PEO.

Request #5:

5. *Scope and inspection recommendations of GALL Report AMP XI.M29, "Aboveground Metallic Tanks"*
   a. *State whether there are any in-scope indoor welded storage tanks that meet all of the following criteria:*
      i. *have a large volume (i.e., greater than 100,000 gallons)*
      ii. *are designed to near-atmospheric internal pressures*
      iii. *sit on concrete or soil*
      iv. *are exposed internally to water*
   b. *State how LRA Section 3 Table 2s and Appendices A.1.1 and B.1.1 will be revised to be consistent with the attached Table 5a. Alternatively, state and justify portions that will not be consistent.*

Table 5a Tank Inspection Recommendations[1,7]				
Material	*Environment*	*AERM*	*Inspection Technique[9]*	*Inspection Frequency*
Inspections to identify aging of inside surfaces of tank shell, roof, and bottom Inside Surface (IS), Outside Surface (OS)[6,8]				
Steel	*Raw water*	*Loss of material*	*Visual from IS or Volumetric from OS[10]*	*Each 10-year period starting 10 years before the period of extended operation*
Steel	*Treated water*	*Loss of material*	*Visual from IS or Volumetric from OS[10]*	*One-time inspection conducted in accordance with AMP XI.M32*
Stainless steel	*Treated water*	*Loss of Material*	*Visual from IS or Volumetric from OS[10]*	*One-time inspection conducted in accordance with AMP XI.M32*
Aluminum	*Treated water*	*Loss of Material*	*Visual from IS or Volumetric from OS[10]*	*One-time inspection conducted in accordance with AMP XI.M32*
Inspections to identify aging of external surfaces of tank roof and tank shell, and bottom not exposed to soil or concrete				

Table 5a Tank Inspection Recommendations[1,7]				
Material	Environment	AERM	Inspection Technique[9]	Inspection Frequency
Steel	Air – indoor controlled Air – indoor uncontrolled Air – outdoor	Loss of material	Visual from OS	Each refueling outage interval
Stainless steel	Air – indoor controlled Air – indoor uncontrolled	Cracking	Surface [11]	Each 10-year period starting 10 years before the period of extended operation
Stainless steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval[5]
		Cracking	Surface[11]	Each 10-year period starting 10 years before the period of extended operation
Aluminum	Air – indoor controlled Air – indoor uncontrolled	Cracking	Surface[11]	Each 10-year period starting 10 years before the period of extended operation
Aluminum	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[11]	Each 10-year period starting 10 years before the period of extended operation
Inspections to identify aging of external surfaces of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS[4]	Each 10-year period starting 10 years before the period of extended operation[3]
Stainless steel	Soil or concrete	Loss of material	Volumetric from IS[4]	Each 10-year period starting 10 years before the period of extended operation[3]
Aluminum	Soil or concrete	Loss of Material	Volumetric from IS[4]	Each 10-year period starting 10 years before the period of extended operation[3]

1. GALL Report AMP XI.M30, "Fuel Oil Chemistry," is used to manage loss of material on the internal surfaces of fuel oil storage tanks. GALL Report AMP XI.M42 is used to manage loss of material and cracking for the external surfaces of buried tanks.
2. A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if the fuel oil specifications have not been changed since 35 years prior to placing the tank in service, or an evaluation has been conducted documenting that any change would not adversely impact the tank's internal surfaces (e.g., low sulfur fuel interaction with coatings).
3. A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted prior to the PEO and during each 10-year period during the PEO demonstrates that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. Alternatively, a one-time inspection conducted in accordance with GALL Report

Table 5a Tank Inspection Recommendations[1,7]				
Material	Environment	AERM	Inspection Technique[9]	Inspection Frequency

AMP XI.M32 may be conducted in lieu of periodic inspections if the bottom of the tank has been cathodically protected such that the availability and effectiveness criteria of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'," Table 4a., "Inspection of Buried Pipe," have been met commencing 5 years prior to the PEO, and the criteria continues to be met throughout the PEO. The evaluation should include soil sampling from underneath the tank.

4. *When volumetric examinations of the tank bottom cannot be conducted due to the tank being coated, an exception should be stated, and the accompanying justification for not conducting inspections should include the considerations in footnote 3, above, or an alternative examination methodology is proposed.*
5. *A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted prior to the PEO and during each 10-year period during the PEO demonstrates that environmental impacts due to such factors as the plant being located within approximately 5 miles of a saltwater coastline, those within 1/2 mile of a highway that is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources are not present in the vicinity of the plant. The evaluation should include soil sampling in the vicinity of the tank (soil results are indicative of compounds atmospheric fallout that could be present on surfaces of the tank) to ensure that chlorides are not present at sufficient levels to cause pitting and crevice corrosion.*
6. *Inspections to identify aging of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces. Where this is not possible due to tank configuration (e.g., tanks with floating covers or bladders the LRA should include a justification for how aging effects will be detected prior to loss of intended function.*
7. *When one-time internal inspections in accordance with the above footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5 year period prior to commencement of the PEO.*
8. *For tank configurations where deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the tank bottom internal inspections should include inspections of the side wall of the tank up to the top of the sludge affected region.*
9. *Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated effective at detecting the AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.*
10. *At least 25 percent of the tank's internal surface is inspected by a method capable of precisely determining wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be qualified and demonstrated effective by the applicant.*
11. *A minimum of either a combination of 25 1-square-foot sections for tank surfaces and for welds, 1-linear-foot of weld length; or 20 percent of the tank's surface are examined. The sample inspection points are distributed such that inspections occur in those areas most susceptible to cracking (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).*

TVA Response to RAI 3.0.3-1 (Request #5)

5.

a. Review of the SQN component database indicates that there are two indoor welded storage tanks that meet the following criteria:
   i. have a large volume (i.e., greater than 100,000 gallons)
   ii. are designed to near-atmospheric internal pressures
   iii. sit on concrete or soil
   iv. are exposed internally to water

   The two tanks are the chemical and volume control system (CVCS) holdup tanks.

b. Changes to LRA Table 3.3.2-10, CVCS, and LRA Table 3.4.1 will reflect the addition of the Aboveground Metallic Tanks Program for the tanks identified in response to 5.a. above. Changes to LRA Sections A.1.1 and B.1.1 are shown with additions underlined and deletions lined through.

   The table of tank inspection details is added without underlining to promote readability of the text. In addition, the table of tank inspection details includes minor variations from the table provided in the RAI as follows.

   - Removed note 2 and renumbered subsequent notes. Note 2 applied to diesel fuel storage tanks, which are addressed in a different program as indicated in note 1.
   - In note 9, removed "qualified and." The meaning of "qualified" is not defined and may not be clear because the inspections are not ASME Section XI inspections. The phrase "demonstrated effective by the applicant" adequately conveys the intent of the note.
   - A number of editorial changes intended to provide clarification and eliminate ambiguity were also made.

Table 3.3.2-10: Chemical and Volume Control System

Component Type	Intended function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Tank	Pressure boundary	Stainless steel	Concrete [ext]	Loss of material	Aboveground Metallic Tanks	VIII.E.SP-137	3.4.1-31	C, 312

3.0 Aging Management Review Results Page 3.3-72

Notes for Tables 3.3.2-1 through 3.3.2-17-32

Plant-Specific Notes

312. The CVCS holdup tanks are indoor tanks on a concrete foundation with an oiled sand cushion.

Table 3.4.1: Steam and Power Conversion Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-31	Stainless steel, aluminum tanks exposed to soil or concrete	Loss of material due to pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Consistent with NUREG-1801. Loss of material for stainless steel tanks exposed to concrete or soil is managed by the Aboveground Metallic Tanks Program. This item applies to components in Tables 3.2.2-1 and 3.3.2-10. There are no stainless steel or aluminum tanks exposed to concrete or soil in the steam and power conversion systems in the scope of license renewal.

A.1.1 Aboveground Metallic Tanks Program

The Aboveground Metallic Tanks Program includes outdoor tanks on soil or concrete and indoor large volume water tanks situated on concrete that are designed for internal pressures approximating atmospheric pressure. Periodic external visual and surface examinations are sufficient to monitor degradation. Internal visual and surface examinations are conducted in conjunction with measuring the thickness of the tank bottoms to ensure that significant degradation is not occurring and that the component's intended function is maintained during the PEO. Internal inspections are conducted whenever the tank is drained, with a minimum frequency of at least once every 10 years, beginning in the 10-year interval prior to the PEO.~~manages loss of material and cracking for the outer surfaces of the aboveground metallic 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 period of extended operation and whenever the tanks are drained during the period of extended operation.~~

The following table provides tank inspection details.[1, 6]

Material	Environment	AERM	Inspection Technique[8]	Inspection Frequency
Inspections to identify aging of inside surfaces of tank shell, roof, and bottom Inside Surface (IS), Outside Surface (OS)[5,7]				
Steel	Raw water	Loss of material	Visual from IS or Volumetric from OS[9]	Each 10-year period starting 10 years before the PEO
Steel	Treated water	Loss of material	Visual from IS or Volumetric from OS[9]	One-time inspection conducted in accordance with AMP XI.M32
Stainless steel	Treated water	Loss of Material	Visual from IS or Volumetric from OS[9]	One-time inspection conducted in accordance with AMP XI.M32
Aluminum	Treated water	Loss of Material	Visual from IS or Volumetric from OS[9]	One-time inspection conducted in accordance with AMP XI.M32
Inspections to identify aging of external surfaces of tank roof and tank shell, and bottom not exposed to soil or concrete				
Steel	Air – indoor controlled Air – indoor uncontrolled Air – outdoor	Loss of material	Visual from OS	Each refueling outage interval
Stainless steel	Air – indoor controlled Air – indoor uncontrolled	Cracking	Surface [10]	Each 10-year period starting 10 years before the PEO
Stainless steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval[4]
		Cracking	Surface[10]	Each 10-year period starting 10 years before the PEO
Aluminum	Air – indoor controlled Air – indoor uncontrolled	Cracking	Surface[10]	Each 10-year period starting 10 years before the PEO
Aluminum	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[10]	Each 10-year period starting 10 years before the PEO

Material	Environment	AERM	Inspection Technique[8]	Inspection Frequency
Inspections to identify aging of external surfaces of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS[3]	Each 10-year period starting 10 years before the PEO[2]
Stainless steel	Soil or concrete	Loss of material	Volumetric from IS[3]	Each 10-year period starting 10 years before the PEO[2]
Aluminum	Soil or concrete	Loss of Material	Volumetric from IS[3]	Each 10-year period starting 10 years before the PEO[2]

1. GALL Report AMP XI.M30, "Fuel Oil Chemistry," is used to manage loss of material on the internal surfaces of fuel oil storage tanks. GALL Report AMP XI.M42 is used to manage loss of material and cracking for the external surfaces of buried tanks.
2. A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted prior to the PEO and during each 10-year period during the PEO demonstrates that the soil under the tank is not corrosive by using actual soil samples that are analyzed for each individual parameter (resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity.
   Alternatively, a one-time inspection may be conducted in accordance with GALL Report AMP XI.M32 in lieu of periodic inspections if the bottom of the tank has been cathodically protected such that the availability and effectiveness criteria of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'," Table 4a., "Inspection of Buried Pipe," have been met commencing 5 years prior to the PEO, and the criteria continues to be met throughout the PEO. The evaluation should include soil sampling from underneath the tank.
3. When volumetric examinations of the tank bottom cannot be conducted due to the tank being coated, an exception should be stated, and the accompanying justification for not conducting inspections should include the considerations in footnote 2 above. Otherwise, an alternative examination method is proposed.
4. A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted prior to the PEO and during each 10-year period during the PEO demonstrates the absence of the following detrimental environmental factors:
   1) Plant location within approximately 5 miles of a saltwater coastline or within 1/2 mile of a highway that is treated with salt for snow or ice control,
   2) Tank location on soil containing more than trace chlorides,
   3) Plant operates cooling towers where the water is treated with chlorine or chlorine compounds, and

4) Plant location in areas subject to chloride contamination from agricultural or industrial sources. The evaluation should include soil sampling in the vicinity of the tank (soil sampling results are indicative of contaminants from atmospheric fallout that could be present on surfaces of the tank) to ensure that chlorides are not present at sufficient levels to cause pitting and crevice corrosion.

5. Inspections to identify the effects of aging on the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces. Where this is not possible due to tank configuration (e.g., tanks with floating covers or bladders), the LRA should include a justification for how aging effects will be detected prior to loss of intended function.
6. When one-time internal inspections in accordance with the above footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 10-year interval prior to the PEO.
7. For tank configurations where deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the tank bottom internal inspections should include inspections of the side wall of the tank up to the top of the sludge-affected region.
8. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated effective at detecting the AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.
9. At least 25 percent of the tank's internal surface is inspected by a method capable of precisely determining wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be demonstrated effective by the applicant.
10. A minimum of either 25 1-square-foot sections of the tank surfaces, including at least 1-linear-foot of weld length; or 20 percent of the tank's surface are examined. The sample inspection points are distributed such that inspections occur in those areas most susceptible to cracking (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).

This program will be implemented prior to the PEO. (See Commitment #1)

B.1.1 ABOVEGROUND METALLIC TANKS

Program Description

The Aboveground Metallic Tanks AMP ~~Program~~ is a new program that ~~will~~ manages loss of material and cracking of ~~for~~ the ~~outer~~ outside and inside surfaces of the aboveground ~~metallic~~ tanks situated on concrete or soil.~~using periodic visual inspections on tanks within the scope of the program as delineated in 10 CFR 54.4.~~ Outdoor tanks, except fire water storage tanks, and certain indoor tanks are included. The program relies on

periodic inspections to monitor for the effects of aging. Tank inside surfaces are inspected by visual or surface examination methods as necessary to detect the applicable aging effects.~~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 effects of aging on the bottom surface of aboveground metallic tanks, which are supported~~constructed~~ on earthen or concrete foundations.~~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.~~

Tank inspections are performed in accordance with the table in LRA Section A.1.1.

This program will be implemented prior to the PEO. (See Commitment #1)

Conclusion

The Aboveground Metallic Tanks Program will be effective at identifying and managing the aging effects of loss of material and cracking on the ~~outer~~ outside and inside surfaces of the in-scope tanks, since it will incorporate proven monitoring techniques, acceptance criteria, corrective actions, and administrative controls. The Aboveground Metallic Tanks Program provides reasonable assurance that the effects of aging will be managed such that applicable components will continue to perform their intended functions consistent with the current licensing basis through the PEO.

RAI 3.5.2.3.4-1a (Follow-up)

Background:

The response to RAI 3.5.2.3.4-1 stated that:

1. *Jacketing is not present on all in-scope fiberglass and calcium silicate insulation exposed to uncontrolled indoor air in LRA Table 3.5.2-4 with a function to limit heat transfer.*
2. *When jacketing is provided, the installation is performed in accordance with "skill-of-the-craft."*
3. *Leakage and spray, if occurring, are abnormal conditions that are identified, corrected and evaluated for the potential effect on surrounding equipment, as necessary, under the corrective action program and work control processes.*
4. *A review of plant-specific operating experience identified no aging effects that resulted in a loss of intended function for insulation.*

LRA Table 3.0-2 defines uncontrolled indoor air as "[a]ir with temperature less than 150°F, humidity up to 100% and protected from precipitation." The definition continues by stating, "[h]umidity levels up to 100 percent are assumed and the surfaces of components in this environment may be wet."

Issue:

The staff found the response to RAI 3.5.2.3.4-1 unacceptable because while the staff acknowledges that leakage and spray are abnormal conditions that would be addressed by the corrective action program and work control process, the insulation is exposed to indoor uncontrolled air. The staff lacks sufficient information to conclude that routine sweating of pipes that could drip onto unjacketed insulation located below the pipe during humid conditions would be identified in the corrective action program. In addition, the applicant did not provide any evidence to demonstrate that the "skill-of-the-craft" approach for installing jacketing has been effective.

If the mechanical system environment of indoor air been selected, the staff would still find the response to be unacceptable. LRA Table 3.0-1, Service Environments for Mechanical Aging Management Reviews," defines indoor air as, "[a]ir in an environment protected from precipitation." The corresponding definition in GALL Report Table IX.D for air-indoor uncontrolled is, "[u]ncontrolled indoor air is associated with systems with temperatures higher than the dew point (i.e., condensation can occur, but only rarely; equipment surfaces are normally dry). Although condensation occurs rarely in this air environment, insulation can retain the condensation and its ability to reduce heat transfer will be degraded.

Request:

Amend the LRA to include aging management of reduction of insulation effectiveness for in-scope fiberglass and calcium silicate insulation ***or****:*

1. *State whether sweating of pipes during plant operation is identified as a condition adverse to quality in the corrective action program. If it is, provide evidence that either sweating is not occurring or that it has routinely been identified and corrected.*
2. *State whether any in-scope unjacketed fiberglass or calcium silicate insulation is installed, or could be installed in the future, in locations that are susceptible to wetting by sweating of pipes during plant operation.*
3. *State what evidence is available that "skill-of-the-craft" has been sufficient to ensure that insulation jacketing has been installed in a manner that will preclude insulation moisture intrusion.*

TVA Response to RAI 3.5.2.3.4-1a

The below changes to the LRA are made to include managing the effects of aging on fiberglass and calcium silicate insulation due to potential exposure to moisture that can cause loss of insulation effectiveness.

Based on these changes, a response to request parts 1, 2 and 3 is not necessary.

The changes to SQN LRA Table 3.5.2-4, Notes for Tables 3.5.2-1 through 3.5.2-4, Section A.1.40 and Section B.1.40 follow with additions underlined and deletions lined through.

Table 3.5.2-4: Bulk Commodities

Structure and/or Component or Commodity	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
Insulation ~~(includes jacketing, wire mesh, tie wires, straps, clips)~~	IN, SNS	Fiberglass, calcium silicate	Air-indoor uncontrolled	~~None~~ Loss of material, Change in material properties	~~None~~ Structures Monitoring			J~~, 503~~

Notes for Table 3.5.2-1 through 3.5.2-4

~~503. Loss of insulating characteristics due to insulation degradation is not an aging effect requiring management for insulation material. Insulation products, which are made from fiberglass fiber, calcium silicate, stainless steel, and similar materials, in an air – indoor uncontrolled environment do not experience aging effects that would significantly degrade their ability to insulate as designed. A review of site operating experience identified no aging effects for insulation used at SQN.~~

A.1.40 Structures Monitoring Program

- Revise Structures Monitoring Program procedures to include the following in-scope structural components and commodities.
  - Insulation (fiberglass, calcium silicate)
- Revise Structures Monitoring Program procedures to include the following parameters to be monitored or inspected:
  - Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness.
- Revise Structures Monitoring Program procedures to include the following for detection of aging effects:
  - Inspection of insulation (fiberglass, calcium silicate) to manage loss of material and change in material properties due to exposure to moisture that can cause loss of insulation effectiveness.
- 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.

B.1.40 Structures Monitoring

Enhancements

The following enhancements will be implemented prior to the PEO.

Elements Affected	Enhancements
1. Scope of Program	Revise Structures Monitoring Program procedures to include the following in-scope structural components and commodities: Insulation (fiberglass, calcium silicate)
3. Parameters Monitored or Inspected	Revise Structures Monitoring Program procedures to include the following parameters to be monitored or inspected: • Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness.
4. Detection of Aging Effects	Revise Structures Monitoring Program procedures to include the following for detection of aging effects: • Inspection of insulation (fiberglass, calcium silicate) to manage loss of material and change in material properties due to exposure to moisture that can cause loss of insulation effectiveness.

6. Acceptance Criteria	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.

Commitment changes

Revise Commitment 31 parts C, G, and H. Add new commitment 31.K as shown below. Additions are shown with underlines.

C. Revise Structures Monitoring Program procedures to include the following in-scope structural components and commodities:

- Insulation (fiberglass, calcium silicate)

G. Revise Structures Monitoring Program procedures to include the following parameters to be monitored or inspected:

- Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness.

H. Revise Structures Monitoring Program procedures to include the following for detection of aging effects:

- 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.

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.

RAI B.1.41-3a (Follow-up)

Background:

By letter dated July 1, 2013, the applicant provided its response to RAI B.1.41-3 that addressed the scope of inspection in the Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS) Program. In its response, the applicant stated that when the inspection option is selected for aging management of CASS components, the scope of the inspection covers those portions of the CASS components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations in accordance with the GALL Report.

Issue:

For those CASS components that are screened as being susceptible to loss of fracture toughness due to thermal aging embrittlement, the GALL Report permits an applicant to select either inspection or performance of a flaw tolerance evaluation to manage the aging effect in the susceptible components. However, the applicant's response does not clearly address whether or not the limiting portions of each susceptible component will be inspected if the inspection option is selected.

Request:

Clarify whether or not the scope of inspection covers the limiting portions of each susceptible component if the inspection option is selected.

TVA Response to RAI B.1.41-3a

As recommended in NUREG-1801, Section XI.M12, all components determined to be potentially susceptible to thermal aging embrittlement are within the scope of this program.

Use of a flaw tolerance evaluation is the preferred approach to demonstrate that potentially susceptible components have adequate toughness.

In the event that a volumetric inspection method becomes qualified for this application, TVA may use this approach to perform inspections for some or all potentially susceptible components in lieu of the flaw tolerance evaluation.

For components selected for inspection, the limiting portions of the component from the standpoint of applied stress, operating time and environmental considerations will be included, as recommended by NUREG-1801, Section XI.M12.

RAI B.1.2-2a (Follow-up)

Background:

The response to RAI B.1.2-2, dated July 1, 2013, stated that the normally inaccessible submerged bolted connections associated with the essential raw water cooling (ERCW) pumps are visually inspected for loss of material when they are made accessible during maintenance. The response also stated that the frequency of inspection is adequate to prevent significant age-related degradation.

Issue:

The staff requires an understanding of the anticipated frequency of inspection of the normally submerged ERCW bolted connections and the basis for determining that the frequency is adequate to prevent significant age-related degradation.

Request:

1. *State the estimated inspection frequency for the normally submerged ERCW bolted connections during the PEO and the basis for that estimation, including such information as historical maintenance or planned activities. In addition, justify why that frequency will be sufficient to manage loss of material for the bolting.*
2. *Absent a justification for the proposed opportunistic inspections, state the minimum number of inspections that will be conducted to ensure that aging effects for ERCW bolting will be age managed during the PEO.*

TVA Response to RAI B.1.2-2a

1. SQN will visually inspect a representative sample of ERCW system submerged bolts at least once every five years during the PEO. It is anticipated that divers will perform the inspections. (See Commitment 2.D)

   Recent operating experience provides the basis for the inspection frequency of at least once every five years.

   The N-B ERCW pump was installed in 1993 and replaced in 2013. Maintenance personnel stated that during the N-B ERCW pump replacement, all of the normally submerged bolting was loosened with common tools, indicating no significant bolting degradation. Because the ERCW pump bolts incurred no significant degradation during 20 years of submergence, a visual inspection of a representative sample of normally submerged pump bolts at least once every five years provides reasonable assurance that significant degradation can be identified prior to loss of intended function.

   The representative sample for submerged bolts will be 20% of the population, with a maximum of 25, during each five year inspection interval. The inspection focuses on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. Adverse bolting indications observed during inspections are entered into the plant corrective action program.

2. A minimum of three ERCW bolted inspections will be performed during the PEO.

Changes to **LRA Section B.1.2** and **LRA Section A.1.2** follow with additions underlined and deletions lined through.

"B.1.2 Bolting Integrity

The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 ksi), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. This program supplements the inspection activities required by ASME Section XI for ASME Class 1, 2 and 3 bolting. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspections (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. ~~Normally inaccessible~~ A representative sample of submerged bolts ~~bolted connections~~ in the ERCW system are visually inspected for degradation~~when they are made accessible during associated component maintenance activities~~ at least once every five years. The representative sample for ERCW system submerged bolts will be 20% of the population, with a maximum of 25, during each five year inspection interval. The inspection of ERCW system submerged bolts focuses on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. Visual inspection methods are effective in detecting the applicable aging effects and the frequency of inspection is adequate to prevent significant age-related degradation. With the exception of one reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (Section B.1.33), no high-strength bolting has been identified at SQN. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, are used to delineate the program.

The following enhancements will be implemented prior to the PEO.

Element Affected	Enhancement
2. Preventive Actions	Revise Bolting Integrity Program procedures to ensure the actual yield strength of replacement or newly procured bolts will be less than 150 ksi.
4. Detection of Aging Effects	Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer canal isolation valve flange bolts.
4. Detection of Aging Effects	Revise Bolting Integrity Program procedures to visually inspect a representative sample of normally submerged ERCW system bolts at least once every 5 years.

7. Corrective Actions	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.

A.1.2 Bolting Integrity Program

The Bolting Integrity Program manages loss of preload, cracking, and loss of material for closure bolting for safety-related and nonsafety-related pressure-retaining components using preventive and inspection activities. This program does not include the reactor head closure studs or structural bolting. Preventive measures include material selection (e.g., use of materials with an actual yield strength of less than 150 kilo-pounds per square inch [ksi]), lubricant selection (e.g., restricting the use of molybdenum disulfide), applying the appropriate preload (torque), and checking for uniformity of gasket compression where appropriate to preclude loss of preload, loss of material, and cracking. This program supplements the inspection activities required by ASME Section XI for ASME Class 1, 2 and 3 bolting. For ASME Code Class 1, 2, and 3, and non-ASME Code class bolts, periodic system walkdowns and inspection (at least once per refueling cycle) ensure identification of indications of loss of preload (leakage), cracking, and loss of material before leakage becomes excessive. ~~Normally inaccessible~~ A representative sample of submerged bolts ~~bolted connections~~ in the ERCW system are visually inspected for degradation ~~when they are made accessible during associated component maintenance activities~~at least once every five years. The representative sample for ERCW system submerged bolts will be 20% of the population, with a maximum of 25, during each five year inspection interval. The inspection of ERCW system submerged bolts focuses on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. Visual inspection methods are effective in detecting the applicable aging effects and the frequency of inspection is adequate to prevent significant age-related degradation. With the exception of one reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (Section A.1.33), no high-strength bolting has been identified at SQN. Identified leaking bolted connections will be monitored at an increased frequency in accordance with the corrective action process. Applicable industry standards and guidance documents, including NUREG-1339, EPRI NP-5769, and EPRI TR-104213, are used to delineate the program.

The Bolting Integrity Program will be enhanced as follows.

- Revise Bolting Integrity Program procedures to ensure the actual yield strength of replacement or newly procured bolts will be less than 150 ksi.
- 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.

- Revise Bolting Integrity Program procedures to specify a corrosion inspection and a check-off for the transfer tube isolation valve flange bolts.
- Revise Bolting Integrity Program procedures to visually inspect a representative sample of normally submerged ERCW system bolts at least once every five years."

Commitment # 2.D has been added.

ENCLOSURE 2

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

Revised Responses to RAI B.1.9-1a and B.1.4-4b, and revision to LRA page 2.4-44

RAI B.1.9-1a

Background: The Staff observed in the EQ Health reports that two indicators in the EQ program health report (3 & 6E) have been designated as yellow for three years. These issues also appear in the applicant's assessment reports without resolution.

Issue: The staff is concerned that LRA EQ AMP B.1.9 may not meet the GALL Report AMP X.E1 corrective actions program element when implemented by the applicant.

- *3 – Identified that the qualified permanent backup engineer position has been vacant since October 2010.*
- *6E – Identified that no permanent maintenance EQ coordinator is available at Sequoyah which resulted in two instances of site EQ procedure violations.*

Request: Explain the actions taken to resolve the EQ program health reports yellow indicators 3 and 6E.

Revised TVA Response to RAI B.1.9-1a

Note: Revisions are in *italics and underlined*. Deletions are in ~~*italics and lined through*~~. This revised response supersedes the response provided to the NRC on July 29, 2013, ADAMS No. ML13213A027, page 26 of 50 in the Enclosure.

The two program health report indicators (3 and 6E) are unrelated to the corrective action program element in NUREG-1801, Section X.E1 which states the following.

> "If an EQ component is found to be outside the bounds of its qualification basis, corrective actions are implemented in accordance with the station's corrective action program. When unexpected adverse conditions are identified during operational or maintenance activities that affect the environment of a qualified component, the affected EQ component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. When an emerging industry aging issue is identified that affects the qualification of an EQ component, the affected component is evaluated and appropriate corrective actions are taken, which may include changes to the qualification bases and conclusions. Confirmatory actions, as needed, are implemented as part of the station's corrective action program, pursuant to 10 CFR 50, Appendix B. As discussed in the Appendix for GALL, the staff finds the requirements of 10 CFR Part 50, Appendix B, acceptable to address the corrective actions."

The health report indicators were not related to the EQ qualification basis, adverse environmental conditions that could affect the qualified component, or an emerging industry aging issue that affects the qualified component. Therefore, this is not an issue of ineffective corrective actions. Nonetheless, SQN intends to resolve the yellow program health report indicators as described below.

EQ program health report yellow indicator 3

The Engineering Programs manager *has been* ~~is~~ utilizing a qualified electrical design engineer as a backup to the EQ Program owner. This EQ Program staffing arrangement has resulted in no challenges to any EQ component qualification basis. ~~*The yellow window indicates only that current staffing arrangement is not optimal for EQ Program efficiency considerations.*~~

A fully qualified electrical design engineer is now designated as a backup to the EQ Program owner. As a result, the EQ program health report indicator 3 is forecast to improve to a "white or green" rating in the next reporting period.

EQ program health report yellow indicator 6E

The EQ program health report indicator 6E identified that the transmittal of an EQ maintenance work order completion form by the performing organization to the EQ program owner was not completed in a timely manner (15 days after completing the EQ work) as specified by the EQ program procedure.

This condition involved the organization performing the work not meeting the timeliness provisions of the procedure. The lack of a Maintenance EQ Program coordinator to facilitate the transfer of the EQ work completion forms to the EQ Program owner contributed to the delay in updating EQ program records following EQ maintenance. The Maintenance EQ coordinator is not a position defined in the EQ Program procedure.

The EQ maintenance coordinator position has now been staffed. The assigned individual has completed the necessary training requirements.

These EQ Program staffing issues have not resulted in challenges to the qualification basis for any EQ component.

As a result of new personnel assignments, the EQ program health indicator 6E is forecast to improve to a "white" rating in the next reporting period.

~~*The resolution plans to improve the yellow indicators to acceptable status are being addressed in the SQN corrective action program.*~~

RAI B.1.4-4b

Background:

LRA Section B.1.4 states, "[i]f cathodic protection is not provided prior to the period of extended operation, the program will include documented justification that cathodic protection is not warranted."

LR-ISG-2011-03 states that the justification for not having cathodic protection must be provided in the LRA.

Issue:

During the audit, the staff reviewed a Corrpro Report titled, "TVA - Sequoyah Nuclear Plant - Buried Piping Integrity Program Corrosion Assessment Report." This report cited several examples demonstrating that the soil at Sequoyah is corrosive and recommended installation of cathodic protection in some locations with in-scope piping. Based on input received during audit breakout sessions, it was noted that a new study was recently completed by a different vendor. The new study was not available for review by the staff during the audit.

Request:

1. *If cathodic protection will not be installed, provide an analysis for not providing cathodic protection 10 years prior to commencing the period of extended operation consistent with the recommended detail in LR-ISG-2011-03 Section 2.a.iii.*
2. *If cathodic protection will not be installed, state the results of a 10 -year search of plant-specific operating experience related to in-scope and out-of-scope buried piping consistent with the recommended detail in LR-ISG-2011-03 Section 2.a.iv.*
3. *Based on the results of (a) and (b) above, state what adjustments to the program will be implemented if cathodic protection is not installed and the study results demonstrate adverse results. If no adjustments will be made, state the basis for why reasonable assurance can be established that the buried in-scope components will meet their intended function consistent with the current licensing basis.*

NRC Follow up questions for B.1.4-4b (via telecom)

Background: TVA's B.1.4-4 RAI response on July 25, 2013 revised the LRA Table 3.4.2-2 by deleting the soil environment for piping and bolting.

- *If the piping and bolting is not exposed to soil, what environment is it exposed to in the path from the condensate storage tank to the auxiliary feedwater pump suction?*
- *Is this piping in-scope?*
- *If this piping is in-scope, and if it passes through a pipe tunnel, is the access to the tunnel unrestricted?*
- *If this piping is in-scope, what program will be used to manage the loss of material (piping and bolting) and loss of preload (bolting) aging effects?*

Revised TVA Response to RAI B.1.4-4b

Note, revisions are in *italics and underlined*. This revised response supersedes the response provided to the NRC by letters dated:

- July 25, 2013, ADAMS No. ML13213A026, in the Enclosure 1, page 10 of 11, and
- August 9, 2013, ADAMS No. ML13225A387, in the Enclosure 4, page 4 of 5.

1. Cathodic protection will be provided based on the guidance of NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03. Thus, as indicated in LRA section B.1.4, the Buried and Underground Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03, including provisions for providing cathodic protection. *(See Commitment # 3.B)*
2. Cathodic protection will be provided.
3. Cathodic protection will be provided, so no adjustments are necessary.

LRA Appendix A and B Changes

"The changes to **LRA Appendix A, Section A.1.4,** (Buried and Underground Piping and Tanks Inspection Program) and **LRA Appendix B, Section B.1.4,** (Buried and Underground Piping and Tanks Inspection Program) follow with additions underlined and deletions lined through.

> "The Buried and Underground Piping and Tanks Inspection Program manages loss of material and cracking for the external surfaces of buried and underground piping fabricated from carbon steel and stainless steel through preventive measures (i.e., coatings, backfill, and compaction), mitigative measures (e.g., electrical isolation between piping and supports of dissimilar metals), and periodic inspection activities (i.e., direct visual inspection of external surfaces, protective coatings, wrappings, and quality of backfill) during opportunistic or directed excavations. There are no underground or buried tanks at SQN for which aging effects are managed by the Buried and Underground Piping and Tanks Inspection Program.
>
> Based on the guidance of NUREG-1801, Section XI.M41, as modified by LR-ISG-2011-03, cathodic protection will be provided at SQN prior to the period of extended operation of Unit 1.
>
> ~~Cathodic protection is not installed. If cathodic protection is not provided prior to the period of extended operation, the program will include documented justification that cathodic protection is not warranted. The justification should include the results of soil testing (including tests for soil resistivity, corrosion-accelerating bacteria, pH, moisture, chlorides and redox potential) to demonstrate that the soil environment is not corrosive to applicable buried components. The results of a review of at least ten years of operating experience must support the conclusion that cathodic protection is not warranted. The review of ten years of operating experience will include review of operating experience with components not in the scope of license renewal if they are fabricated from the same materials and exposed to the same environments as in-scope buried and underground components.~~

~~If a reduction in the number of inspections recommended in Table 4a of NUREG-1801, Section XI.M41 is claimed based on a lack of soil corrosivity as determined by soil testing, then soil testing should be conducted once in each ten-year period starting ten years prior to the period of extended operation.~~ This program will be implemented prior to the period operation."

NUREG-1801 Consistency

The Buried and Underground Piping and Tanks Inspection Program will be consistent with the program described in NUREG-1801, Section XI.M41, Buried and Underground Piping and Tanks as modified by LR-ISG-2011-03."

In addition to the above, it has been determined that the main and auxiliary feedwater *(AFW)* systems do not have piping or bolting exposed to soil. *The reason the soil environment was removed is because the AFW piping and bolting are in an accessible tunnel.*

The AFW piping and bolting in the tunnel are contained in LRA Table 3.4.2.2 with external environment of outdoor and indoor air.

The AFW piping is in-scope; see LRA drawings 47W804-1; 1,2-47W804-2; 1,2-47W803-2. Access to the tunnel is unrestricted.

The External Surface Monitoring Program is managing the loss of material for the piping in the tunnel.

The Bolting Integrity Program is managing the loss of material and loss of preload for bolting in the tunnel.

Therefore, the Buried and Underground Piping and Tanks Inspection Program is not applicable.

The change to **LRA Table 3.4.2-2** line items follows with deletions lined through.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
~~Piping~~	~~Pressure boundary~~	~~Carbon steel~~	~~Soil (ext)~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks Inspections~~	~~VIII.G.SP-145~~	~~3.4.1-47~~	~~A~~
~~Bolting~~	~~Pressure boundary~~	~~Carbon steel~~	~~Soil (ext)~~	~~Loss of material~~	~~Buried and Underground Piping and Tanks Inspections~~	~~VIII.H.SP-141~~	~~3.4.1-50~~	~~A~~
~~Bolting~~	~~Pressure boundary~~	~~Carbon steel~~	~~Soil (ext)~~	~~Loss of preload~~	~~Bolting Integrity~~	~~VIII.H.SP-142~~	~~3.4.1-6~~	~~A~~

The change to **LRA Table 3.4.1** line items follows with additions underlined and deletions lined through.

Table 3.4.1: Steam and Power Conversion Systems					
Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommendation	Discussion
3.4.1-6	Steel, stainless steel bolting exposed to soil	Loss of preload	Chapter XI.M18, "Bolting Integrity Program"	No	~~Consistent with NUREG-1801. Loss of preload for steel bolting exposed to soil is managed by the Bolting Integrity Program.~~ There is no buried steel or stainless steel bolting in the steam and power conversion systems in the scope of license renewal.
3.4.1-47	Steel (with coating or wrapping), stainless steel, nickel alloy piping, piping components, and piping elements; tanks exposed to soil or concrete	Loss of material due to general, pitting, crevice, and microbiologically influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	~~Consistent with NUREG-1801. Loss of material for steel components exposed to soil is managed by the Buried and Underground Piping and Tanks Inspection Program.~~ There are no buried steel ~~tanks~~, ~~or~~ stainless steel or nickel alloy components exposed to soil or concrete in the steam and power conversion systems in the scope of license renewal.
3.4.1-50	Steel bolting exposed to soil	Loss of material due to general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	~~Consistent with NUREG-1801. Loss of material for steel bolting exposed to soil is managed by the Buried and Underground Piping and Tanks Inspection Program~~. There is no steel bolting exposed to soil in the steam and power conversion systems in the scope of license renewal.

Change to **Section 3.4.2.1.2** is with deletion lined through.

3.4.2.1.2 Main and Auxiliary Feedwater

Environments

- Lube oil
- ~~Soil~~
- Treated water

NRC request for clarification regarding SQN Station Black Out (SBO) transformers (in an email from the NRC to TVA from Mr. Emmanuel Sayoc on August 14, 2013)

LRA Section 2.4 (page 2.4-44, 3rd paragraph, and first sentence), comment from the NRC staff:

> *"When reviewing the SBO recovery path for Sequoyah in LRA Section 2.4 describes that there are four transformers that make up the SBO recovery path. However, the one line SQN electrical diagram that came with the LRA and the additional write-ups imply that there are three SBO recovery common station service transformers (CSST), which are CSST A, B, and C. There is no CSST D, which is contrary to what is stated in the LRA Section 2.4 (page 2.4-44, 3rd paragraph, and first sentence). This may be a misprint in the LRA Section 2.4."*

TVA Response

SBO restoration information found in LRA Section 2.4 (page 2.4-44, 3rd paragraph, and first sentence) is revised with deletions lined through.

> "The offsite power source required to support SBO recovery is ~~the Chickamauga No. 1 Line or Watts Bar Hydro Line,~~ fed through one of the common station service transformers (CSST) A, B ~~,~~or C ~~or D~~."

ENCLOSURE 3

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

Regulatory Commitment List, Revision 6

Commitments 2.D, 31.C/G/H and 31.K have been revised. Additions are underlined.

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. <u>Revise Bolting Integrity Program procedures to visually inspect a representative sample of normally submerged ERCW system bolts at least once every 5 years.</u> (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 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 period of extended operation 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	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. 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
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 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.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.11
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	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 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.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.13

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	• 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 period of extended operation. A representative number is 20% of the population (defined as locations having the same material, environment, and aging effect combination) with a maximum of 25 locations. Additional inspections will be performed as needed to obtain this representative sample prior to the period of extended operation and periodically during the period of extended operation based on the findings from the inspections performed prior to the period of extended operation. C. 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. 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.		
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*. (TVA Response to Set 6.60day RAI *B.1.14-1 and B.1.38-1)*	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.14

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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
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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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 period of extended operation and at least every ten years thereafter based on initial testing to determine possible changes in boron-10 areal density. 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.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.22
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	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
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	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.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.31

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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
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 period of extended operation.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.35

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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 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	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.40

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• 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) • 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		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	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 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		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	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). • <u>Monitor the surface condition of insulation (fiberglass, calcium silicate) to identify exposure to moisture that can cause loss of insulation effectiveness.</u> 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.		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	• 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. 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.		
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 • 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)	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(33)	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
35	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.	SQN1: Prior to 09/17/20 SQN2: Not Applicable	B.1.6

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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
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, EDMS # L44130725002)	No later than the scheduled issue date of the renewed operating licenses for SQN Units 1 & 2.	B.0.4

The above table identifies the **37** SQN NRC LR commitments. Any other statements in this letter are provided for information purposes and are not considered to be regulatory commitments.