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

CNL-13-103

October 17, 2013

10 CFR Part 54

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

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

Subject: **Response to NRC Request for Additional Information Regarding the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application, Sets 8 (B.1.33-1), 10 (3.0.3-1 Request 1), 12 (B.1.23-2b), 13 (30-day), 14 (B.0.4-1a) (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. 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. ML13213A026)
3. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 10," dated August 2, 2013 (ADAMS Accession No. ML13204A257)
4. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 12," dated August 30, 2013 (ADAMS Accession No. ML13238A244)
5. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 13," dated September 16, 2013 (ADAMS Accession No. ML13256A007)
6. NRC Letter to TVA, "Requests for Additional Information for the Review of the Sequoyah Nuclear Plant, Units 1 and 2, License Renewal Application - Set 14," dated September 26, 2013 (ADAMS Accession No. ML13263A338)

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NRR

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.

By Reference 2, TVA responded to the NRC request for additional information (RAI) labeled Set 8, which included a response to RAI B.1.33-1. Enclosure 1 provides a supplement to the TVA response to RAI B.1.33-1.

By Reference 3, the NRC forwarded an RAI labeled Set 10 that included RAI 3.0.3-1, Request 1, with a required response due date no later than October 31, 2013. Enclosure 1 provides the response to this portion of the RAI.

By Reference 4, the NRC forwarded an RAI labeled Set 12 that included RAI B.1.23-2b with a required response due date no later than September 30, 2013. However, Mr. Richard Plasse, NRC Project Manager for the SQN License Renewal, has given a verbal extension for the response to RAI B.1.23-2b until October 29, 2013. Enclosure 1 provides the response to RAI B.1.23-2b.

By Reference 5, the NRC forwarded an RAI labeled Set 13 that included specific RAIs with a required response due date no later than October 16, 2013, i.e., the 30-day subset of RAIs. However, Mr. Plasse has given a verbal extension for the response to Set 13 (30-day) to October 17, 2013. Enclosure 2 provides the responses for the 30-day set of RAIs, with the exception of RAI B.1.41-4a, for which Mr. Plasse has given a verbal extension until November 15, 2013.

By Reference 6, the NRC forwarded an RAI labeled Set 14 that included RAI B.0.4-1a with a required response due date no later than October 28, 2013. Enclosure 1 provides the response to this RAI.

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 17th day of October 2013.

Respectfully,

J. W. Shea
Vice President, Nuclear Licensing

Enclosures
cc: See Page 2

Enclosures:

1. TVA Responses to NRC Request for Additional Information: Sets 8 (B.1.33-1), 10 (3.0.3-1 Request 1), 12 (B.1.23-2b), and 14 (B.0.4-1a)
2. TVA Responses to NRC Request for Additional Information: Set 13 (30-day)
3. Regulatory Commitment List, Revision 9

cc (Enclosures):

NRC Regional Administrator – Region II
NRC Senior Resident Inspector – Sequoyah Nuclear Plant

ENCLOSURE 1

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

TVA Responses to NRC Request for Additional Information:
Sets 8 (B.1.33-1), 10 (3.0.3-1 Request 1), 12 (B.1.23-2b), and 14 (B.0.4-1a)

Set 8: **RAI B.1.33-1 Supplement:** Changes to SQN **LRA Appendixes A.1.2** and **B.1.2**

In the TVA response to NRC Request for Additional Information (RAI) B.1.33-1 (Letter dated July 25, 2013, ADAMS Accession No. ML13213A026, page E2 – 11 of 35), it was stated that **no** reactor head closure studs were considered high strength for LRA Section B.1.33.

In a recent review of the Sequoyah Nuclear Plant (SQN) LRA Appendixes A.1.2 and B.1.2, the following statement was noted in both appendixes:

> "With the exception of **one** reactor vessel closure stud, which is managed by the Reactor Head Closure Studs Program (LRA Section B.1.33), no high-strength bolting has been identified at SQN."

Thus, the current LRA Appendixes A .1.2 and B.1.2 are incorrect. Changes to SQN LRA Appendixes A.1.2 and B.1.2 should have been included with the TVA response to RAI B.1.33-1 on July 25, 2013.

Therefore, changes to SQN LRA Appendixes B.1.2 and 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. A representative sample of submerged bolts in the ERCW system ~~are~~ is visually inspected for degradation 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), n~~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.

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. A representative sample of submerged bolts in the ERCW system ~~are~~ is visually inspected for degradation 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), n~~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."

***Set 10*: RAI 3.0.3-1 Request 1**

Issue:

1. *Recurring internal corrosion*

   When the staff reviewed recent LRAs and industry OE, it was evident that some plants have experienced repeated instances of internal aging in piping systems that should result in the aging effect to be considered recurring. In each of these instances, the applicant had to augment LRA AMPs and AMR items to fully address the aging effect during the period of extended operation (PEO). To date, examples of these aging effects have involved microbiologically-influenced corrosion (MIC).

   Potential augmented aging management activities include: alternative examination methods (e.g., volumetric versus external visual), augmented inspections (e.g., a greater number of locations, additional locations based on risk insights based on susceptibility to aging effect and consequences of failure, a greater frequency of inspections), and additional trending parameters and decision points where increased inspections would be implemented.

   Recurring internal corrosion is identified by both the number of occurrences of internal aging effects with similar aging mechanisms and the extent of degradation at each localized site.

   a. *The term "recurring internal corrosion" is not intended to address aging effects that occur infrequently or occurred frequently in the past but have been subsequently corrected. An aging effect should be considered recurring from a frequency perspective if the search of plant-specific OE reveals repetitive occurrences (e.g., one per refueling outage cycle) of aging effects with the same aging mechanisms in the same material environment that have occurred over three or more sequential or non-sequential cycles.*
   b. *The staff recognizes that not all aging effects are significant enough to warrant augmented aging management requirements. As a plant ages there can be numerous examples of inconsequential aging effects. This request for additional information (RAI) is focused on recurring internal corrosion in which the component's degree of degradation is significant such that it either does not meet plant-specific acceptance criteria (e.g., component had to be repaired or replaced, component was declared inoperable), or the degradation exceeds wall penetration greater than 50 percent, regardless of the minimum wall thickness.*

      The staff also recognizes that in many instances a component would be capable of performing its intended function even if the degradation met this threshold. For example, localized 50 percent deep pits in typical service water systems do not challenge the pressure boundary function of a component. Nevertheless, the staff has established this threshold for further evaluation as a conservative way of identifying cases that could warrant consideration of augmented aging management actions.

Based on the industry OE, only components in the Engineered Safety Features Systems (LRA Section 3.2), Auxiliary Systems (LRA Section 3.3), and Steam and Power Conversion Systems (LRA Section 3.4) need to be addressed.

Request:

1. *Recurring internal corrosion*
   a. *Based on the results of a review of the past 10 years of plant-specific OE, state whether recurring internal corrosion has occurred, as described above.*
   b. *If recurring internal aging corrosion has occurred, describe each aging effect and the reason for being considered as recurring internal corrosion.*
   c. *If recurring internal corrosion has occurred, state the following:*
      i. *Why the applicable program's examination methods will be sufficient to detect the recurring aging mechanism before affecting the ability of a component to perform its intended function.*
      ii. *The basis for the adequacy of augmented or lack of augmented inspections.*
      iii. *What parameters will be trended as well as the decision points where increased inspections would be implemented (e.g., extent of degradation at individual corrosion sites, rate of degradation change).*
      iv. *The basis for parameter testing frequency and how it will be conducted.*
      v. *How inspections of not easily accessed components (i.e., buried, underground) will be conducted.*
      vi. *If buried components are involved, how leaks will be identified.*
      vii. *The program(s) that will be augmented to include the above requirements.*

TVA Response to RAI 3.0.3-1 Issue 1

a. Based on the results of a review of the past 10 years of plant-specific operating experience, microbiologically influenced corrosion (MIC) of carbon steel piping components exposed to raw water is a recurring internal corrosion (RIC). TVA considers MIC to be a RIC. MIC has occurred in carbon steel components exposed to raw water of the following systems.
   - System 24 – Raw cooling water (RCW)
   - System 25 – Raw service water (RSW)
   - System 26 – High pressure fire protection (HPFP)
   - System 27 – Condenser circulating water (CCW)
   - System 67 – Essential raw cooling water (ERCW)

b. In carbon steel piping components exposed to raw water, loss of material due to MIC leading to through-wall leaks has occurred at least once in each of three refueling cycles in the last ten years. Because of this repetitive failure, TVA considers MIC to be a RIC.

c. RIC due to MIC in Carbon Steel Piping Components Exposed to Raw Water

   i. TVA monitors loss of material due to MIC in carbon steel piping components exposed to raw water at Sequoyah Nuclear Plant (SQN). TVA monitors wall thinning of carbon steel piping exposed to raw water and replaces pipe where necessary.

MIC degradation monitoring uses ultrasonic (UT) measurements to determine wall thickness at selected locations that are marked with inspection grids. The selected locations, which provide a representative sample of the piping system, are chosen based on pipe configuration (horizontal pipe, vertical pipe, pipe connections such as tees); flow conditions (low or moderate flow, stagnant, intermittent flow, stagnant flow in branch close to main line flow); and operating history (known degradation or leakage). The selected grid locations are periodically reviewed to validate their relevance and usefulness. New grid locations are added as new information, e.g., changes in system operations, becomes available.

The UT measurements at each selected location are compared to the nominal pipe wall thickness (for initial measurements) or to previous thickness measurements to determine rates of corrosion and the estimated time to reach T_{min}. Subsequent UT measurements are performed quarterly as determined necessary based on the rate of corrosion and expected time to reach T_{min}. In the last five years, approximately 70 inspections have been performed at approximately 45 identified grid locations.

Components are replaced, if necessary, based on the rate of corrosion and the difference between measured wall thickness and T_{min} . If wall thickness is found to be less than T_{min}, the issue is entered into the corrective action program (CAP) for resolution.

MIC degradation monitoring has been effective in identifying internal piping corrosion. Neither pipe leaks nor pipe wall thinning has resulted in the loss of a component's ability to support system pressure and flow requirements.

ii. As discussed in the above response to Request c.i., the SQN MIC degradation monitoring has been effective in identifying loss of material due to MIC for carbon steel components exposed to raw water. The number of inspections and the interval between inspections are determined based on inspection results. The fact that neither pipe leaks nor pipe wall thinning has resulted in the loss of component ability to support system pressure and flow requirements indicate the adequacy of this approach.

iii. As discussed in the above response to Request c.i., component wall thickness is the parameter monitored to evaluate RIC due to MIC. Wall thickness measurements are taken at multiple locations representing a variety of system configurations. The inspection timing is routinely established based on the rate of corrosion and expected time to reach T_{min}.

iv. As discussed in the above response to Request c.i., the timing of inspections required at a given location is based on the rate of corrosion and expected time to reach T_{min}. The nominal quarterly inspection frequency provides adequate opportunity to inspect any location that might exhibit a higher than expected rate of wall thinning.

v. The HPFP system 26 and ERCW system 67 include sections of buried piping that are not readily inspected for MIC degradation. However, new technologies for inspecting buried piping to identify internal corrosion are being developed and are expected to be significantly improved before the end of the current license term for SQN. Prior to the period of extended operation (PEO), SQN will select an inspection method (or methods) that will provide suitable indication of piping wall thickness for a representative sample of buried piping locations to supplement the existing inspection locations. (See Commitment 9.F)

vi. Although underground leaks are possible, leaks large enough to affect the function of these systems are expected to develop slowly. Such leaks are detectable by changes in system performance (e.g., changes in instrumentation readings or reduced cooling capacity), changes in system operation (e.g., more frequent jockey pump operation), or by the appearance of wetted ground around the leak.

vii. The Periodic Surveillance and Preventive Maintenance Program will be augmented to incorporate the MIC degradation monitoring activities. (See Commitment 24)

The change to **LRA Section A.1.31** (new item in the list of program activities, starting on LRA page A-24) follows with additions underlined.

- Perform wall thickness measurements using UT or other suitable techniques at selected locations to identify loss of material due to microbiologically Influenced corrosion (MIC) in carbon steel piping components exposed to raw water in the following systems.

    - System 24 – Raw cooling water
    - System 25 – Raw service water
    - System 26 – High Pressure Fire Protection
    - System 27 – Condenser circulating water
    - System 67 – Essential raw cooling water

  Choose selected locations based on pipe configuration, flow conditions and operating history to represent a cross-section of potential MIC sites. Periodically review the selected locations to validate their relevance and usefulness, and modify accordingly.

  Compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation.

Compare wall thickness measurements to minimum allowable wall thickness (T_{min}) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements at intervals determined for each selected location based on the rate of corrosion and expected time to reach T_{min}.

Prior to the period of extended operation, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations.

The change to **LRA Section B.1.31** (new table line in the Program Description) follows with additions underlined.

Carbon steel piping components exposed to raw water	Perform wall thickness measurements using UT or other suitable techniques at selected locations to identify loss of material due to microbiologically Influenced corrosion (MIC) in carbon steel piping components exposed to raw water in the following systems. System 24 – Raw cooling water System 25 – Raw service water System 26 – High pressure fire protection System 27 – Condenser circulating water System 67 – Essential raw cooling water Choose selected locations based on pipe configuration, flow conditions and operating history to represent a cross-section of potential MIC sites. Periodically review the selected locations to validate their relevance and usefulness, and modify accordingly. Compare wall thickness measurements to nominal wall thickness or previous measurements to determine rates of corrosion degradation. Compare wall thickness measurements to minimum allowable wall thickness (T_{min}) to determine acceptability of the component for continued use. Perform subsequent wall thickness measurements at intervals determined for each selected location based on the rate of corrosion and expected time to reach T_{min}. Prior to the PEO, select a method (or methods) from available technologies for inspecting internal surfaces of buried piping that provides suitable indication of piping wall thickness for a representative set of buried piping locations to supplement the set of selected inspection locations.

Commitment #9.F has been added.

<u>Set 12</u>: RAI B.1.23-2b

<u>Background:</u>

In its July 1, 2013 response to RAI B.1.23-2, the applicant indicated that wear occurred in the thermal sleeves of control rod drive mechanism (CRDM) nozzles due to interactions with the CRDM nozzles. The CRDM nozzle thermal sleeves perform the following functions: (1) shielding the CRDM nozzles from thermal transients, (2) providing a lead-in for the rod cluster control assembly (RCCA) drive rods into the CRDM nozzles, and (3) protecting the RCCA drive rods from the head cooling spray cross flow in the reactor vessel upper head plenum region.

<u>Issue:</u>

The applicant's operating experience indicates that wear occurred in these thermal sleeves. The LRA does not address aging management for loss of material due to wear of the CRDM nozzle thermal sleeves.

<u>Request:</u>

The LRA does not address aging management for loss of material due to wear of the CRDM nozzle thermal sleeves. Identify an aging management program for these thermal sleeves and describe how the applicant's program will adequately manage loss of material due to wear for the CRDM nozzle thermal sleeves.

<u>TVA Response to RAI B.1.23-2b</u>

To address loss of material due to wear of the CRDM nozzle (also known as head adapter) thermal sleeves, the below change to the LRA reflects the use of the Inservice Inspection Program described in LRA Section B.1.16 for aging management. In parallel with the volumetric examination or surface examination performed on the reactor pressure vessel (RPV) head CRDM nozzles, the thermal sleeves are examined for loss of material in accordance with Westinghouse Technical Bulletin TB-07-2. The examination inspects underneath the RPV head where the thermal sleeves penetrate in the two outer most concentric rows of CRDM nozzles. Areas of loss of material are identified and documented in the CAP.

The changes to **LRA Table 2.3.1-2** Reactor Vessel Internal Components Subject to Aging Management Review follow with additions underlined.

Component Type	Intended Function
<u>CRDM thermal sleeve</u>	<u>Structural support</u>

<u>Reference</u>:

Westinghouse Technical Bulletin TB-07-2, Revision 1, Reactor Vessel Head Adapter Thermal Sleeve Wear, June 8, 2007

The changes to affected **LRA Table 3.1.2-2**: Reactor Vessel Internals follow with additions underlined.

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Program	NUREG-1801 Item	Table 1 Item	Notes
<u>CRDM thermal sleeve</u>	<u>Structural support</u>	<u>Stainless steel</u>	<u>Treated borated water > 140°F</u>	<u>Loss of material due to wear</u>	<u>Inservice Inspection</u>	<u>IV.B2.RP-382</u>	<u>3.1.1-32</u>	<u>C</u>
<u>CRDM thermal sleeve</u>	<u>Structural support</u>	<u>Stainless steel</u>	<u>Treated borated water > 140°F</u>	<u>Loss of material</u>	<u>Water Chemistry Control Primary and Secondary</u>	<u>IV.A2.RP-28</u>	<u>3.1.1-88</u>	<u>C</u>
<u>CRDM thermal sleeve</u>	<u>Structural support</u>	<u>Stainless steel</u>	<u>Treated borated water > 140°F</u>	<u>Cracking</u>	<u>Water Chemistry Control Primary and Secondary</u> <u>Inservice Inspection</u>	<u>IV.A2.RP-55</u>	<u>3.1.1-47</u>	<u>C</u>

The changes to **LRA Table 3.1.1** Reactor Coolant System follow with additions underlined and deletions lined through.

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.1.1-32	Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure components, exposed to reactor coolant and neutron flux	Cracking, or loss of material due to wear	Chapter XI.M1, "ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	~~Cracking and l~~Loss of material due to wear of the ~~reactor vessel internals core support structure components~~ <u>CRDM nozzle thermal sleeves</u> is managed by the ~~Reactor Vessel Internals Program which uses ASME Section X~~I Inservice Inspection Program~~, Subsections IWB as required. These AMR results are compared to other table items (3.1.1-53 and 3.1.1-59)~~.

***Set 14:* RAI B.0.4-1a**

Background

In its July 29, 2013, response to RAI B.0.4-1, the applicant provided additional information on its programmatic activities for the ongoing review of operating experience. The applicant provided this information to support consistency of these activities with the areas described in Appendix B to the GALL Report, which the NRC established in Final License Renewal Interim Staff Guidance, LR-ISG-2011-05, "Ongoing Review of Operating Experience," dated March 16, 2012.

RAI B.0.4-1a Issue 1

Based on the response to RAI B.0.4-1, the staff could not ascertain whether certain aspects of the applicant's operating experience review activities are fully consistent with Appendix B to the GALL Report. Specifically:

1) *Appendix B to the GALL Report states that NRC and industry guidance documents and standards applicable to aging management should be considered as sources of operating experience, and there should be written plans and expectations for finding and processing these sources. The applicant stated that it uses its Operating Experience Program to monitor industry operating experience based on Institute of Nuclear Power Operations (INPO) guidelines. The INPO guidelines identify certain sources of NRC and industry operating experience, but there are other sources that could be applicable to aging management. The applicant did not describe how it will identify and evaluate these other sources.*

Request 1: *If demonstrating consistency with Appendix B to the GALL Report, address the following:*

Describe the written plans and expectations for finding and processing sources of NRC and industry guidance documents and standards applicable to aging management that are not covered by the sources listed in the INPO guidelines.

TVA Response to RAI B.0.4-1a, Request 1

1. TVA will be consistent with Appendix B of the NUREG-1801, Generic Aging Lessons Learned (GALL) Report.

   The TVA response to RAI B.0.4-1 contained within the letter dated July 29, 2013 (ADAMS Accession No. ML13213A027), stated that the written plans and expectations for Operating Experience (OE) and CAP procedures will be enhanced to address unanticipated degradation or impacts to aging management activities.

   The proposed TVA OE and CAP procedures revisions will add references to the NUREG-1801, the NRC, and industry guidance documents and standards applicable to age-related degradation and aging management as sources of OE. TVA's current OE process includes a review and screening of incoming plant-specific AMP OEs from INPO, the NRC notification document, daily publication of the Scientech Today, and industry-initiated guidance documents and standards.

TVA AMP OE procedure enhancements will require the OE Coordinators at SQN to flag OE involving unanticipated degradation or impacts to the TVA aging management activities for further evaluation by the AMP SME via the initiation of a CAP problem evaluation report (PER). Additionally, multi-TVA sites OE conference calls are routinely held to ensure full consideration of the OE source documents for fleet impact. OEs, for AMP issues that require further evaluation by the AMP Subject Matter Expert (SME), will be entered into the TVA CAP for SQN to review; and if applicable, for TVA fleet wide review.

Periodic AMP assessment: The OE procedure enhancements will direct TVA fleet OE coordinators/AMP SME to perform periodic assessment of

(1) Systems, structures, and components

(2) Materials

(3) Environments

(4) Aging effects

(5) Aging mechanisms

(6) AMPs

(7) The activities, criteria, and evaluations integral to the elements of the AMPs

If it is found that the effects of aging are not being adequately managed, then actions will be initiated to either enhance the AMPs or develop and implement new AMPs.

RAI B.0.4-1a Issue 2

2) *Appendix B to the GALL Report states that any adverse trends associated with age-related degradation trend codes should be entered into the corrective action program for evaluation. The applicant stated that its Corrective Action Program includes trend codes for identifying aging management and license renewal items, and it periodically reviews these codes for trends. However, the applicant did not describe how it will address adverse trends.*

Request 2: Indicate whether adverse trends identified from review of the aging management and license renewal trend codes will be entered into the Corrective Action Program for evaluation.

TVA Response to RAI B.0.4-1a, request 2

2. Age-related degradation and aging management activities adverse trends, identified from the review of the aging management and license renewal trend codes in CAP, will be entered into TVA CAP for further evaluation. This is a written requirement in the existing CAP procedure for trend review and for the identification and correction of adverse trend. (See Commitment #37)

RAI B.0.4-1a Issue 3

3) *Appendix B to the GALL Report states that personnel responsible for implementing the aging management programs and processing plant-specific and industry operating experience should receive training on age-related degradation and aging management topics. The applicant stated that it trains personnel based on the complexity of the job performance requirements and assigned responsibilities. However, the applicant did not indicate that this training specifically includes topics on age-related degradation and aging management.*

Request 3: Demonstrate that personnel training will include topics on age-related degradation and aging management.

If not demonstrating consistency with Appendix B to the GALL Report, justify why the operating experience review activities provide for the adequate consideration of operating experience involving age-related degradation and aging management to maintain the effectiveness of the aging management programs and activities.

Identify any necessary enhancements to existing activities based on the response to this request.

Provide the schedule for implementing these enhancements and a justification if implementation is later than the date when the renewed operating license is scheduled to be issued, if approved.

TVA Response to RAI B.0.4-1a, request 3

3. Training was provided to key personnel at SQN who prepared the aging program documents for the LRA and who responded to the associated RAIs. The training addressed the preparation, analysis, review, and approval of the AMP documents and license renewal activities.

   The OE Job Familiarization process will be enhanced to address age management topics and periodic training including provisions to accommodate the turnover of plant personnel. TVA OE Job Familiarization training program is currently in-place for new OE Site Coordinators. The purpose of the training is to provide a structured orientation of the roles and responsibilities of screening, assigning and evaluating plant-specific OE items.

   The TVA training program for key Engineering personnel responsible for implementing the aging management programs and processing plant-specific aging management OE will be enhanced to address age management topics and periodic training for continued education and for the turnover of plant personnel.

   The initial and continuing Engineering Support Personnel Training Program will be enhanced to address training on current and emerging/future aging management topics.

   A comprehensive and holistic AMP training topic list will be developed before the date the SQN renewed operating license is scheduled to be issued. The TVA aging management and license renewal implementation training enhancement will include relevant AMPs topics for SQN.

An example of the flow accelerated corrosion (FAC) AMP topic is listed below.

- Classroom training in engineering concepts related to a nuclear power generating station AMP. Typical classroom learning objectives for these topics include:
  - Describe how FAC occurs and what type of piping it commonly attacks
  - Identify what types of systems are susceptible to microbiologically induced corrosion; impact for AMP
  - Discuss fatigue monitoring and its purpose
  - Discuss NRC and the utility industrial AMP OEs for cracking in internal vessel components
- Required reading and demonstrated knowledge of NRC regulations, industry guidance/standards, TVA fleet AMP procedures, and site-specific instructions regarding potential aging effects and the activities designed to prevent, detect, monitor, trend, evaluate, and correct these effects. Some examples include:
  - NRC Bulletin 87-01, Thinning of Pipe in Nuclear Power Plants
  - NRC Generic Letter 89-08, Erosion/Corrosion Induced Pipe Wall Thinning
  - NSAC 202L, EPRI Report, Recommendations for an Effective FAC Program
  - INPO EPG-06 FAC
  - TVA fleet procedures for FAC Program
  - TVA standards for FAC Scanning and Gridding
- Demonstration of the ability to perform AMP-related activities within a mentored training environment. Examples for the FAC Program include:
  - Develop an inspection plan from industry AMP OE
  - Evaluate inspection results and perform a wall thinning evaluation in accordance with applicable procedures
  - Report problem identified, first by writing/documenting the problem with a PER, then to the SQN AMP SME
  - Communicate/share SQN AMP OEs to the TVA fleet/Nuclear Industry

TVA will be consistent with Appendix B of the NUREG-1801, GALL Report. The TVA AMP OE Process, AMP adverse trending & evaluation in CAP, AMP Initial and Refresher Training will be fully implemented by the date the SQN renewed operating license is scheduled to be issued.

Commitment #37 has been revised.

Please review RAI response A.1-1a in Enclosure 2 of this letter for additional discussion of the SQN AMP OE process.

ENCLOSURE 2

Tennessee Valley Authority

Sequoyah Nuclear Plant, Units 1 and 2 License Renewal

TVA Responses to NRC Request for Additional Information: Set 13 (30-day)

RAI 4.7.3-3a

Background:

By letter dated July 29, 2013, the applicant responded to RAI 4.7.3-3. In its response to RAI 4.7.3-3, the applicant provides additional information to support the conclusion that the time-limited aging analysis (TLAA) on the leak-before-break (LBB) analysis will remain valid for the period of extended operation, as accepted in accordance with the requirement in 10 CFR 54.21 (c)(1)(i).

Issue:

The staff noted that, with the exception of the following transients, the information in LRA Tables 4.3-1 and 4.3-2 provides adequate demonstration that number of cycles projected at 60 years for the design transients assumed in the LBB analysis would not exceed the number cycles assumed for these transient in the LBB analysis. However, LRA Table 4.3-1 for Unit 1 and LRA Table 4.3-2 for Unit 2 do not provide any 60-year cycle projections for the following design basis transients.

- *Load follow cycles for unit loading and unloading at a rate of 5 percent of full power/min*
- *Step load increases and decrease*
- *Cold hydrostatic test*

Request:

Provide the 60-year projected cycle values and justify the 60-year projected cycle values for the following design transients assumed for in the LBB: (a) load follow cycles for unit loading and unloading at a rate of 5% of full power/min, (b) step load increases and decreases, and (c) cold hydrostatic tests. Based on the cycle projections for these transients, provide your basis for concluding that the LBB analysis for the CLB would remain valid for the period of extended operation, as dispositioned in accordance with the TLAA acceptance criterion in 10 CFR 54.21(c)(1)(i).

TVA Response to RAI 4.7.3-3a

(a) Load follow cycles for unit loading and unloading at a rate of 5% of full power/minute

SQN Units 1 and 2 are base-loaded plants for which the "load following" mode of operation is not used.

A value of 18,300 cycles of unit loading and unloading is assumed in the design transient analysis

Unit loading and unloading occurs infrequently. A review of three years of operational data indicates less than 20 loading/unloading cycles (including refueling outages and reactor trips) over that three year time period or an average of seven loading/unloading cycles per unit per year.

A frequency of over 300 times per year would be necessary to accrue 18,300 cycles at the end of the period of extended operation (PEO). Therefore, the 18,300 cycles used in the design transient analysis exceed the number of cycles expected during plant operation through the PEO.

(b) Step load increases and decrease

The 2,000 cycles used in the design transient analysis were step changes of 10% power. Over 30 of these cycles per year would be necessary to accrue 2,000 cycles at the end of the PEO. SQN Units 1 and 2 are base-loaded plants. Therefore, the 2,000 cycles exceed the number of cycles expected during plant operation through the PEO.

(c) Cold hydrostatic test

Cold hydrostatic testing has not been and will not be performed at SQN Units 1 and 2. The 10 cycles used in the design transient analysis exceed the number of cycles that will be experienced during actual plant operation through the PEO.

SQN will revise the SQN UFSAR Table 5.2.1-1 to identify the transients that do not require tracking.

RAI 3.0.3-1, item (5a)

Background:

The staff noted that the Aboveground Metallic Tank program, as amended by letter dated September 3, 2013, allows for a one time inspection of the tank bottom thickness conducted in accordance with the One Time Inspection program, in lieu of periodic inspections. In order to use a onetime inspection, one of the following criteria will be met:

- *The soil under the tank is demonstrated to be not corrosive during each 10 year period starting 10 years prior to the period of extended operation.*
- *The tank bottom has been cathodically protected in accordance with 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."*

The staff also noted that the applicant proposes to conduct the alternative one time inspection within the 10 year period prior to the period of extended operation.

Issue:

Conducting a one time inspection in lieu of periodic inspections when either of the above criteria is met is acceptable. However, GALL Report AMP XI.M29, "Aboveground Metallic Tanks," recommends that tank bottom thickness inspections occur within the 5 year period of entering the period of extended operation.

GALL Report AMP XI.M32, "One Time Inspection," "detection of aging effects" program element allows one time inspections to commence 10 years prior to the period of extended operation. However, inspections associated with GALL Report AMP XI.M32 are based on aging effects that are not expected to occur or the aging effect is expected to progress very slowly. The staff is aware of two recent industry operating experience events related to degradation in tanks of similar design, which was not detected until just prior to entering the period of extended operation.

Request:

Explain why conducting a one time inspection of the tank bottom 10 years prior to entering the period of extended operation will be adequate to confirm that age-related degradation will not cause a loss of intended function during the period of extended operation. Alternatively, amend the Aboveground Metallic Tank program to conduct the alternative one time thickness measurements within the 5 year period prior to the period of extended operation.

TVA Response to RAI 3.0.3-1, item (5a)

The Aboveground Metallic Tanks Program is revised as follows with the additions underlined and deletion lined through to conduct the thickness measurements within the 5-year period prior to the PEO.

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~~5-year interval prior to the PEO.

RAI 3.4.2.1.1-2

Background:

By letter dated September 3, 2013, TVA amended LRA Table 3.3.2-10 to include the chemical and volume control system (CVCS) hold up stainless steel tanks exposed to concrete, which will be managed for loss of material by the Aboveground Metallic Tanks program. The AMR item cited LRA Table 3.4 1, item 3.4.1-31, and plant specific note 312, which states, "[t]he CVCS holdup tanks are indoor tanks on a concrete foundation with an oiled sand cushion." LRA Table 3.3.2-10 states that the outside surfaces of the tanks externally exposed to indoor air have no aging effect requiring management and no recommended aging management program.

LRA Table 3.0-1, "Service Environments for Mechanical Aging Management Reviews," states that the indoor air environment includes the air indoor uncontrolled GALL Report environment.

Issue:

GALL Report Section IX.D, "Selected Definitions and Use of Terms for Describing and Standardizing Environments," states that for the air indoor uncontrolled environment, condensation can occur. Given the potential for periodic condensation, minor amounts of halides can accumulate and result in cracking over time. The staff is aware of industry operating experience where indoor stainless steel atmospheric storage tanks have experienced stress corrosion cracking.

Request:

Explain how cracking will be managed on the external surfaces of the CVCS hold up tanks, or state the basis for why cracking will not occur.

TVA Response to RAI 3.4.2.1.1-2

The chemical and volume control system (CVCS) holdup tanks receive all or a portion of the reactor coolant letdown and clean borated drainage from the CVCS and other systems. The principal source of effluent directed to the holdup tanks is the letdown produced as a result of boric acid concentration dilution in the RCS. The CVCS operates in an indoor air environment for which humidity control is not provided. As defined in the Sequoyah design criteria documents, the operating temperature of the CVCS holdup tank is 130°F. There are no sources of chilled water or raw water that could reduce the tank temperature below the dew point and promote condensation. Consequently, condensation is not expected on the CVCS hold up tanks. TVA reviewed industry operating experience associated with this issue, specifically NRC Information Notice 2013-18 "Refueling Water Storage Tank Degradation." For the two tanks described in this notice with similar design as the CVCS holdup tanks at SQN, condensation leading to an environment conducive to stress corrosion cracking was assessed to be a factor. Given the lack of periodic condensation on the CVCS holdup tanks, this industry operating experience is not applicable. A review of recent condition reports identified no applicable plant-specific operating experience related to cracking of these tanks. Therefore, cracking is not an aging effect requiring management for the CVCS holdup tanks.

RAI A.1-1

Background

LRA Section A.1, as amended by letter dated July 29, 2013, provides the UFSAR supplement summary description of the applicant's ongoing operating experience review activities.

Issue

The applicant's response to RAI B.0.4-1 states that the operating experience review activities include:

- *review of revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," as a source of industry operating experience; and*
- *evaluation of age-related operating experience items based on consideration of affected plant systems, structures, and components; materials; environments; aging effects, aging mechanisms; aging management programs; and the activities, criteria, and evaluations integral to the elements of the aging management programs.*

The summary description in LRA Section A.1 does not address these activities.

Request

Revise LRA Section A.1 to include a description of the activities identified above. Otherwise, provide a justification for not including such a description in the UFSAR supplement.

TVA Response to RAI A.1-1

The change to **LRA Section A.1** follows, with the new additions double underlined and the July 29, 2013 TVA RAI response additions single underlined.

"A.1 AGING MANAGEMENT PROGRAMS

The integrated plant assessment for license renewal identified aging management programs necessary to provide reasonable assurance that components within the scope of license renewal will continue to perform their intended functions consistent with the current licensing basis (CLB) for the PEO. This section describes the aging management programs and activities required during the period of extended operation. Aging management programs will be implemented prior to entering the period of extended operation.

The corrective action, confirmation process, and administrative controls of the SQN (10 CFR Part 50, Appendix B) Quality Assurance Program are applicable to all aging management programs and activities during the period of extended operation. TVA quality assurance (QA) procedures, review and approval processes, and administrative controls are implemented in accordance with the requirements of 10 CFR 50, Appendix B. The SQN Quality Assurance Program applies to safety-related and important-to-safety structures and components. Corrective actions and administrative (document) control for both safety-related and non-safety-related structures and components are accomplished in accordance with the established SQN corrective action program (CAP) and document control program and are applicable to all aging management programs and activities during the period of extended operation. The confirmation process is part of the corrective action program and includes reviews to assure adequacy of corrective actions, tracking and reporting of open corrective actions, and review of corrective action effectiveness. Any follow-up inspection required by the confirmation process is documented in accordance with the corrective action program.

Operating experience (OE) from plant-specific and industry sources is captured and systematically reviewed on an ongoing basis in accordance with the quality assurance program, which meets the requirements of 10 CFR Part 50, Appendix B, and the operating experience program, which meets the requirements of NUREG-0737, "Clarification of TMI Action Plan Requirements," Item I.C.5, "Procedures for Feedback of Operating Experience to Plant Staff." The OE Program includes the review of current and future revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," as a source of industry OE. The evaluation of age-related OE items is based on consideration of affected plant systems, structures, and components; materials; environments; aging effects, aging mechanisms; aging management programs; and the activities, criteria, and evaluations integral to the elements of the aging management programs.

Codes are used in the corrective action program that provide for the comprehensive identification and categorization of aging-specific issues for plant systems, structures, and components within the scope of license renewal.

The operating experience program includes active participation in the Institute of Nuclear Power Operations' operating experience program, as endorsed by the NRC.

In accordance with these programs, all incoming operating experience items are screened to determine whether they may involve age-related degradation or impact to aging management programs (AMPs). Items so identified are further evaluated, and affected AMPs are either enhanced or new AMPs are developed, as appropriate, when it is determined through these evaluations that the effects of aging may not be adequately managed.

Assessments of AMP effectiveness are performed periodically, regardless of whether the AMP acceptance criteria are met. If an assessment concludes that the effects of aging may not be adequately managed, then a corrective action is entered into the corrective action program to either enhance the AMP or develop and implement new AMPs.

Training will be provided on age-related topics for personnel responsible for submitting, screening, assigning, evaluating, or otherwise processing plant-specific and industry operating experience, as well as for personnel responsible for implementing AMPs, is based on the complexity of the job performance requirements and assigned responsibilities. Training is scheduled on a recurring basis, which accommodates the turnover of plant personnel and allows for incorporation of new training content.

Plant-specific operating experience associated with aging management and age-related degradation is reported to the industry in accordance with guidelines established in the operating experience review program.

The following enhancements will be implemented no later than the scheduled issue date of the renewed operating licenses.

- Revise OE Program Procedure to include current and future revisions to NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," as a source of industry OE, and unanticipated age-related degradation or impacts to aging management activities as a screening attribute.
- Revise the CAP Procedure to provide a screening process of corrective action documents for aging management items, the assignment of aging corrective actions to appropriate AMP owners, and consideration of the aging management trend code.
- Revise AMP procedures as needed to provide for review and evaluation by AMP owners of data from inspections, tests, analyses or AMP OEs.
- Revise the OE Program Procedure to provide guidance for reporting plant-specific OE on unanticipated age-related degradation or impact to aging management activities to the TVA fleet and/or INPO.
- Revise the OE, CAP, Initial and Continuing Engineering Support Personnel Training to address age-related topics, the unanticipated degradation or impacts to the aging management activities; including periodic refresher/update training and provisions to accommodate the turnover of plant personnel, and recent AMP-related OE from INPO, the NRC, Scientech, and nuclear industry-initiated guidance documents and standards."
- A comprehensive and holistic AMP training topic list will be developed before the date the SQN renewed operating license is scheduled to be issued.
- TVA AMP OE Process, AMP adverse trending & evaluation in CAP, AMP Initial and Refresher Training will be fully implemented by the date the SQN renewed operating license is scheduled to be issued.

Commitment #37 has been revised.

Please review RAI response B.0.4-1a in Enclosure 1 of this letter for additional discussion of the SQN AMP OE process.

ENCLOSURE 3

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

Regulatory Commitment List, Revision 9

Commitments **9.F** and **37** have been revised with additions 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. Revise Bolting Integrity Program procedures to visually inspect a representative sample of normally submerged ERCW system bolts at least once every 5 years. (See Set 10 (30-day), Enclosure 1, B.1.2-2a)	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.2
3	A. Implement the **Buried and Underground Piping and Tanks Inspection Program** as described in LRA Section B.1.4. B. Cathodic protection will be provided based on the guidance of NUREG-1801, section XI.M41, as modified by LR-ISG-2011-03.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.4

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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
5	A. Revise **Diesel Fuel Monitoring Program** procedures to monitor and trend sediment and particulates in the standby DG day tanks. B. Revise Diesel Fuel Monitoring Program procedures to monitor and trend levels of microbiological organisms in the seven-day storage tanks. C. Revise Diesel Fuel Monitoring Program procedures to include a ten-year periodic cleaning and internal visual inspection of the standby DG diesel fuel oil day tanks and high pressure fire protection (HPFP) diesel fuel oil storage tank. These cleanings and internal inspections will be performed at least once during the ten-year period prior to the period of extended operation 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 and cycle-based fatigue waiver evaluations on an as-needed basis if an allowable cycle limit is approached, or in a case where a transient definition has been changed, unanticipated new thermal events are discovered, or the geometry of components have been modified. E. Revise Fatigue Monitoring Program procedures to track the tensioning cycles for the reactor coolant pump hydraulic studs.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.11
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	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.13

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(9)	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. • 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. <u>F. Prior to the PEO, SQN will select an inspection method (or methods) that will provide suitable indication of piping wall thickness for a representative sample of buried piping locations to supplement the existing inspection locations for high pressure fire protection system 26 and essential raw cooling water system 67.</u>		
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.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.14

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(10)	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*.		
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.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.18

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(13)	D. Revise program procedures to clarify that the acceptance criteria and maintenance and repair activities use the guidance provided in ASME B30.2		
14	Implement the **Internal Surfaces in Miscellaneous Piping and Ducting Components Program** as described in LRA Section B.1.19.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.19
15	Implement the **Metal Enclosed Bus Inspection Program** as described in LRA Section B.1.21.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.21
16	A. Revise **Neutron Absorbing Material Monitoring Program** procedures to perform blackness testing of the Boral coupons within the ten years prior to the 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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
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
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

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

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

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

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

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	material is suspect. Include instructions to augment the visual examination of elastomeric material with physical manipulation of at least ten percent of available surface area. • Opportunistic inspections when normally inaccessible areas (e.g., high radiation areas, below grade concrete walls or foundations, buried or submerged structures) become accessible due to required plant activities. Additionally, inspections will be performed of inaccessible areas in environments where observed conditions in accessible areas exposed to the same environment indicate that significant degradation is occurring. • Inspection of submerged structures at least once every five years. Inspections of water control structures should be conducted under the direction of qualified personnel experienced in the investigation, design, construction, and operation of these types of facilities. • Inspections of water control structures shall be performed on an interval not to exceed five years. • Perform special inspections of water control structures immediately (within 30 days) following the occurrence of significant natural phenomena, such as large floods, earthquakes, hurricanes, tornadoes, and intense local rainfalls. • Insulation (fiberglass, calcium silicate) will be monitored for loss of material and change in material properties due to potential exposure to moisture that can cause loss of insulation effectiveness. I. Revise Structures Monitoring Program procedures to prescribe quantitative acceptance criteria ~~is~~ based on the quantitative acceptance criteria of ACI 349.3R and information provided in industry codes, standards, and guidelines including ACI 318, ANSI/ASCE 11 and relevant AISC specifications. Industry and plant-specific operating experience will also be considered in the development of the acceptance criteria. J. Revise Structures Monitoring Program procedures to clarify that detection of aging effects will include the following. Qualifications of personnel conducting the inspections or testing and evaluation of structures and structural components meet the guidance in Chapter 7 of ACI 349.3R. K. Revise Structures Monitoring Program procedures to include the following acceptance criteria for insulation (calcium silicate and fiberglass) • No moisture or surface irregularities that indicate exposure to moisture. L. Revise Structures Monitoring Program procedures to include the following preventive actions. Specify protected storage requirements for high-strength fastener components (specifically ASTM A325 and A490 bolting).		

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(31)	Storage of these fastener components shall include: 1) maintaining fastener components in closed containers to protect from dirt and corrosion; (2) storage of the closed containers in a protected shelter; (3) removal of fastener components from protected storage only as necessary; and (4) prompt return of any unused fastener components to protected storage.		
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) 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.,	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.42

No.	COMMITMENT	IMPLEMENTATION SCHEDULE	LRA SECTION / AUDIT ITEM
(33)	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
36	Revise **Inservice Inspection Program** procedures to include a supplemental inspection of Class 1 CASS piping components that do not meet the materials selection criteria of NUREG-0313, Revision 2 with regard to ferrite and carbon content. An inspection techniques qualified by ASME or EPRI will be used to monitor cracking. Inspections will be conducted on a sampling basis. The extent of sampling will be based on the established method of inspection and industry operating experience and practices when the program is implemented, and will include components determined to be limiting from the standpoint of applied stress, operating time and environmental considerations.	SQN1: Prior to 09/17/20 SQN2: Prior to 09/15/21	B.1.16

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

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.