UNITED STATES
NUCLEAR REGULATORY COMMISSION
WASHINGTON, D.C. 20555-0001

October 7, 2013

Mr. Adam C. Heflin
Senior Vice President
and Chief Nuclear Officer
Union Electric Company
P.O. Box 620
Fulton, MO 65251

SUBJECT: REQUEST FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE CALLAWAY PLANT, UNIT 1, LICENSE RENEWAL APPLICATION, SET 28 (TAC NO. ME7708)

Dear Mr. Heflin:

By letter dated December 15, 2011, Union Electric Company (Ameren Missouri) (the applicant) submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54 (10 CFR Part 54) for renewal of operating license No. NPF-30 for the Callaway Plant, Unit 1 (Callaway). The staff of the U.S. Nuclear Regulatory Commission (NRC or the staff) is reviewing this application in accordance with the guidance in NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants." During its review, the staff has identified areas where additional information is needed to complete the review. The staff's requests for additional information are included in the enclosure. Further requests for additional information may be issued in the future.

Items in the enclosure were discussed with Sarah G. Kovaleski, of your staff, and a mutually agreeable date for the response is within 90 days from the date of this letter. If you have any questions, please contact me by telephone at 301-415-2946 or by e-mail at Samuel.CuadradoDeJesus@nrc.gov.

Sincerely,

Samuel Cuadrado de Jesús, Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket No. 50-483

Enclosure:
As stated

cc: Listserv

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Samuel Cuadrado de Jesús, Project Manager
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As stated
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CALLAWAY PLANT, UNIT 1

LICENSE RENEWAL APPLICATION

REQUEST FOR ADDITIONAL INFORMATION, SET 28

RAI 3.0.3-1

Background:

Recent industry operating experience (OE) and questions raised during the staff's review of several License Renewal Applications (LRAs) has resulted in the staff concluding that several Aging Management Programs (AMP) and Aging Management Review (AMR) items in the LRA may not or do not account for this OE.

Issue: 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 included 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. 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 10 years of plant-specific OE reveals repetitive occurrences (e.g., one per refueling outage cycle that has occurred over 3 or more sequential or non-sequential cycles) of aging effects with the same aging mechanism.

The staff recognizes that not all aging effects are significant enough to warrant augmented aging management activities. As a plant ages there can be numerous examples of inconsequential aging effects. This 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), or the degradation exceeded 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. The staff does not intend that the 50 percent through-wall penetration or greater criterion be interpreted to indicate that the in-scope component does or did not meet its intended function, but rather as an indicator of aging effects significant enough to warrant enhanced aging management actions. For example, localized 50 percent deep pits in typical service water systems typically do not challenge the pressure boundary function of a component.

Based on the industry OE, 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) should be addressed.

The staff noted that Safety Evaluation Report (SER) Section 3.0.3.2.3 addresses MIC on the internal surfaces of essential service water system piping. However, it is not clear to the staff how the aging effects for the remaining in-scope carbon steel piping will be managed in light of the recurring internal corrosion that occurred in this system.

The staff noted that SER Section 3.0.3.2.7 addresses how MIC on the internal surfaces of fire water system piping will be age-managed during the period of extended operation. The staff's review of these changes to the LRA confirmed that the proposed approach is consistent with this RAI.

Request:

Based on the results of a review of the past 10 years of plant-specific OE, if recurring internal corrosion has occurred in raw water or waste water environments, provide the following (MIC on the internal surfaces of fire water system piping need not be addressed in the response to this RAI):

a. Describe each aging effect and its extent.

b. State why the applicable programs' examination methods will be sufficient to detect the recurring aging mechanism before affecting the ability of a component to perform its intended function.

c. The basis for the adequacy of augmented or lack of augmented inspections.

d. 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).

e. The basis for parameter testing frequency and how it will be conducted.

f. How inspections of not easily accessed components (i.e., buried, underground) will be conducted.

g. If buried components are involved, how leaks will be identified.

h. The program(s) that will be augmented to include the above requirements.

RAI 3.0.3-2

Background:

Recent industry OE and questions raised during the staff's review of several LRAs has resulted in the staff concluding that several AMPs and AMR items in the LRA may not or do not account for this OE.

Issue: Loss of coating integrity for Service Level III and Other coatings

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

For purposes of this RAI:

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

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

c. The term "coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfacers that are designed to adhere to a component to protect its surface.

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

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

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

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

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

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

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

c. All accessible internal surfaces for tanks and heat exchangers should be inspected. A representative sample of internally coated piping components should be inspected based on a 95-percent confidence level.

d. Coatings specialists and inspectors should be qualified in accordance with an American Society for Testing and Materials (ASTM) International standard endorsed in Regulatory Guide (RG) 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," including staff guidance associated with a particular standard.

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

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

The staff noted that essential service water internal coatings were addressed in SER Section 3.0.3.2.3. The staff's evaluation of the proposed approach noted two areas where further information is required for these coatings. These include the inspection interval for newly installed or repaired coatings and the extent of inspections (e.g., number of inspection points or surface area to be inspected).

Request:

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

a. the inspection method

b. the parameters to be inspected

c. when inspections will commence and the frequency of subsequent inspections

d. the extent of inspections and the basis for the extent of inspections if it is not 100 percent

e. the training and qualification of individuals involved in coating inspections

f. how trending of coating degradation will be conducted

g. acceptance criteria

h. corrective actions for coatings that do not meet acceptance criteria, and

i. the program(s) that will be augmented to include the above requirements.

If necessary, provide revisions to LRA Section 3 Table 2s, Appendix A, and Appendix B.

RAI 3.0.3-3

Background:

Recent industry OE and questions raised during the staff's review of several LRAs has resulted in the staff concluding that several AMPs and AMR items in the LRA may not or do not account for this OE.

Issue: Managing aging effects of fire water system components

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

a. The tests and inspections listed in Table 1, "Fire Water System Inspection and Testing Recommendations," of this RAI should be conducted.

b. Wall thickness evaluations used as an alternative instead of flow tests or internal visual examinations for managing flow blockage should not be credited for aging management because external wall thickness measurements may not be capable of identifying when sufficient general corrosion has occurred such that the corrosion products cause flow blockage. The first enhancement associated with the "parameters monitored or inspected," and "detection of aging effects" program element of the Fire Water System Program states that:

> The Fire Water System program will be enhanced to include pipe wall thickness examinations on fire water piping. As an alternative to wall thickness examinations, internal inspections will be performed on accessible exposed portions of fire water piping during plant maintenance activities. Pipe wall thickness examinations and/or internal inspections will be performed prior to the period of extended operation and at 10-year frequencies throughout the period of extended operation.

It is not clear to the staff whether the pipe wall thickness examinations could be conducted exclusively in lieu of internal inspections.

c. If internal visual inspections detect surface irregularities because of corrosion, follow-up volumetric examinations should be performed. These follow-up exams ensure that there is sufficient wall thickness in the vicinity of the irregularity.

d. For portions of water-based fire protection system components that are periodically subjected to flow but designed to be normally dry, such as dry-pipe or preaction sprinkler system piping and valves, augmented inspections should be performed in the portions of this piping that are not configured to completely drain. The augmented inspections should consist of internal visual examination or full flow testing of the entire portion that is not configured to completely drain. Given the potential for accelerated corrosion in the portions of this piping that are not configured to completely drain, periodic wall thickness measurements should be conducted.

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

Request:

a. If inspections of the fire water system components will not be conducted consistent with the guidance in Table 1, provide justification for the currently planned actions previously described in the LRA.

b. If follow-up volumetric examinations will not be conducted when internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal pipe wall thickness, state the basis for why visual inspections alone will provide reasonable assurance that the intended functions of in-scope fire water system components will be maintained consistent with the current licensing basis (CLB) for the PEO. Alternatively, add a requirement to the program to conduct follow-up volumetric examinations.

c. State whether wall thickness evaluations will be used in lieu of conducting flow tests or internal visual examinations, and if it is, state the basis for why wall thickness measurements in the absence of flow testing or internal visual examinations provide reasonable assurance that the intended functions of in-scope fire water system components will be maintained consistent with the CLB for the PEO.

d. For portions of water-based fire protection system components that are periodically subjected to flow but designed to be normally dry, such as dry-pipe or preaction sprinkler system piping and valves, but not configured to completely drain, state the following:

   i. the inspection method to ensure that fouling is not occurring

   ii. the parameters to be inspected

   iii. when inspections will commence and the frequency of subsequent inspections

   iv. the extent of inspections and the basis for the extent of inspections if it is not 100 percent

   v. acceptance criteria, and

vi. how much of this piping will be periodically inspected for wall thickness and how often the inspections will occur.

e. State why conducting inspections consistent with the current provisions in the LRA provides reasonable assurance that the intended functions of fire water storage tank will be maintained consistent with the CLB for the PEO. Alternatively, revise the Fire Water System Program to conduct tank inspections consistent with the inspections recommendations of Table 1.

If necessary, provide revisions to LRA Section 3 Table 2s, Appendix A, and Appendix B.

RAI 3.0.3-4

Background:

Recent industry OE and questions raised during the staff's review of several LRAs has resulted in the staff concluding that several AMPs and AMR items in the LRA may not or do not account for this OE.

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

There have been several instances of OE related to age-related degradation of tanks. Tanks with defects variously described as wall thinning, pinhole leaks, cracks, and through-wall flaws have been identified by detecting external leakage rather than through internal inspections. None of the leaks has resulted in a loss of intended function; however, the number of identified instances of tank degradation and the continued aging of the tanks indicate a need for internal tank inspections to be conducted throughout the PEO. In addition, the staff identified two indoor tanks with external stress-corrosion cracking (SCC) that, except for their location, would normally be in the scope of GALL Report AMP XI.M29. As such, in regard to the recommendations in GALL Report XI.M29, the staff believes that:

a. Certain indoor tanks should be within the scope of GALL Report AMP XI.M29. These include indoor welded storage tanks that meet all of the following criteria:

   i. have a large volume (i.e., greater than 100,000 gallons)

   ii. are designed to near-atmospheric internal pressures

   iii. sit on concrete

   iv. are exposed internally to water

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

c. Based on the tank's material and environment, the attached Table 2, "Tank Inspection Recommendations," contains the types of aging effects requiring management (AERM), inspection type, and frequency of inspections that should be conducted to provide reasonable assurance that the intended functions of the tank will be maintained consistent with the CLB for the PEO.

Request:

a. If there are any in-scope indoor welded storage tanks that meet all of the criteria for inclusion within the scope of GALL Report AMP XI.M29, state why conducting inspections consistent with the current provisions in the LRA provides reasonable assurance that the tank(s)' intended functions will be maintained consistent with the CLB for the PEO. Alternatively, revise the program to conduct tank inspections consistent with Table 2.

b. If necessary, provide revisions to LRA Section 3 Table 2s, Appendix A, and Appendix B.

RAI 3.0.3-5

Background:

Recent industry OE and questions raised during the staff's review of several LRAs has resulted in the staff concluding that several AMPs and AMR items in the LRA may not or do not account for this OE.

Issue: Corrosion under insulation

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

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

a. Periodic inspections should be conducted during each 10-year period of the PEO.

b. For a representative sample of outdoor components, except tanks, and any indoor components operated below the dew point, remove the insulation and inspect a minimum of 20 percent of the in-scope piping length for each material type (i.e., steel, stainless steel, copper alloy, aluminum), or for components where its configuration does not conform to a 1-foot axial length determination (e.g., valve, accumulator), 20 percent of the surface area. Alternatively, remove the insulation and inspect any combination of a minimum of 25 1-foot axial length sections and components for each material type. Inspections are conducted in each air environment (e.g., air-outdoor, moist air) where condensation or moisture on the surfaces of the component could occur routinely or seasonally. In some instances, although indoor air is conditioned, significant moisture can accumulate under insulation during high humidity seasons.

c. For a representative sample of outdoor tanks and indoor tanks operated below the dew point, remove the insulation from either 25 1-square-foot sections or 20 percent of the surface area and inspect the exterior surface of the tank. The sample inspection points should be distributed such that inspections occur on the tank dome, sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects such as on top of stiffening rings.

d. Inspection locations should be based on the likelihood of CUI occurring (e.g., alternate wetting and drying in environments where trace contaminants could be present, length of time the system operates below the dewpoint).

e. Removal of tightly adhering insulation that is impermeable to moisture is not required unless there is evidence of damage to the moisture barrier. If the moisture barrier is intact, the likelihood of CUI is low for tightly adhering insulation. Tightly adhering insulation should be considered to be a separate population from the remainder of insulation installed on in-scope components. The entire population of in-scope piping that has tightly adhering insulation should be visually inspected for damage to the moisture barrier with the same

frequency as for other types of insulation inspections. These inspections would not be credited towards the inspection quantities for other types of insulation.

f. Subsequent inspections may consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation when the following conditions are verified in the initial inspection:

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

   ii. no evidence of SCC.

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

   The staff noted that the removal of insulation to inspect the condensate storage tank and refueling water storage tank external surfaces was addressed in SER Section 3.0.3.2.8. The staff's review of these changes to the LRA confirmed that the proposed approach is consistent with this RAI.

Request:

State why conducting inspections in accordance with the current provisions in the LRA provides reasonable assurance that despite the potential for CUI, the intended function(s) of insulated outdoor components or indoor components operated below the dew point will be maintained consistent with the CLB for the PEO. If necessary, provide revisions to LRA Section 3 Table 2s, Appendix A, and Appendix B.

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

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

Table 2 Tank Inspection Recommendations[1,2]				
Material	Environment	AERM	Inspection Technique[3]	Inspection Frequency
Inspections to identify degradation of inside surfaces of tank shell, roof[4], and bottom Inside Surface (IS), Outside Surface (OS)[5,6]				
Steel	Raw water Waste water	Loss of material	Visual from IS or Volumetric from OS[7]	Each 10-year period starting 10 years before the period of extended operation
Steel	Treated water	Loss of material	Visual from IS or Volumetric from OS[7]	One-time inspection conducted in accordance with AMP XI.M32[8]
Stainless steel	Treated water	Loss of Material	Visual from IS or Volumetric from OS[7]	One-time inspection conducted in accordance with AMP XI.M32[8]
Aluminum	Treated water	Loss of Material	Visual from IS or Volumetric from OS[7]	One-time inspection conducted in accordance with AMP XI.M32[8]
Inspections to identify degradation of external surfaces of tank roof and tank shell, and bottom not exposed to soil or concrete[9]				
Steel	Air – indoor uncontrolled Air – outdoor	Loss of material	Visual from OS	Each refueling outage interval
Stainless steel	Air – indoor uncontrolled	Cracking	Surface [10,11]	Each 10-year period starting 10 years before the period of extended operation
Stainless steel	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[10,11]	Each 10-year period starting 10 years before the period of extended operation
Aluminum	Air – indoor uncontrolled	Cracking	Surface[10,11]	Each 10-year period starting 10 years before the period of extended operation
Aluminum	Air-outdoor	Loss of material	Visual from OS	Each refueling outage interval
		Cracking	Surface[10,11]	Each 10-year period starting 10 years before the period of extended operation
Inspections to identify degradation of external surfaces of tank bottoms and tank shells exposed to soil or concrete				
Steel	Soil or concrete	Loss of material	Volumetric from IS[12]	Each 10-year period starting 10 years before the period of extended operation[13]
Stainless steel	Soil or concrete	Loss of material	Volumetric from IS[12]	Each 10-year period starting 10 years before the period of extended operation[13]

Table 2 Tank Inspection Recommendations[1,2]				
Material	Environment	AERM	Inspection Technique[3]	Inspection Frequency
Aluminum	Soil or concrete	Loss of Material	Volumetric from IS[12]	Each 10-year period starting 10 years before the period of extended operation[13]

Table 2 Tank Inspection Recommendations[1,2]

Material	Environment	AERM	Inspection Technique[3]	Inspection Frequency

1. GALL Report AMP XI.M30, "Fuel Oil Chemistry," is used to manage loss of material on the internal surfaces of fuel oil storage tanks. However, for outdoor fuel oil storage tanks, inspections to identify aging of the external surfaces of tank bottoms and tank shells exposed to soil or concrete are conducted in accordance with this AMP. GALL Report AMP XI.M41 is used to manage loss of material and cracking for the external surfaces of buried tanks.

2. When one-time internal inspections in accordance with these footnotes are used in lieu of periodic inspections, the one-time inspection must occur within the 5-year period prior to commencement of the PEO.

3. Alternative inspection methods may be used to inspect both surfaces (i.e., internal, external) or the opposite surface (e.g., inspecting the internal surfaces for loss of material from the external surface, inspecting for corrosion under external insulation from the internal surfaces of the tank) as long as the method has been demonstrated effective at detecting the AERM and a sufficient amount of the surface is inspected to ensure that localized aging effects are detected. For example, in some cases, subject to being demonstrated effective by the applicant, the low frequency electromagnetic technique (LFET) can be used to scan an entire surface of a tank. If follow-up ultrasonic examinations are conducted in any areas where the wall thickness is below nominal, an LFET inspection can effectively detect loss of material in the tank shell, roof, or bottom.

4. Non-wetted surfaces on the inside of a tank (e.g., roof, surfaces above the normal water line) are inspected in the same manner as the wetted surfaces based on the material, environment, and AERM.

5. Visual inspections to identify degradation of the inside surfaces of tank shell, roof, and bottom should cover all the inside surfaces. Where this is not possible due to tank configuration (e.g., tanks with floating covers or bladders) the LRA should include a justification for how aging effects will be detected prior to loss of intended function.

6. For tank configurations where deleterious materials could accumulate on the tank bottom (e.g., sediment, silt), the tank bottom internal inspections should include inspections of the side wall of the tank up to the top of the sludge affected region.

7. At least 25 percent of the tank's internal surface is inspected by a method capable of precisely determining wall thickness. The inspection method must be capable of detecting both general and pitting corrosion and must be demonstrated effective by the applicant.

8. At least one tank for each material and environment combination should be inspected at each site. The tank inspection can be credited towards the sample population for GALL Report AMP XI.M32.

9. For insulated tanks, the external inspections of tank surfaces that are insulated are conducted in accordance with the sampling recommendations in this AMP. If the initial inspections meet the criteria described in the preceding "Alternatives to Removing Insulation" portion of this AMP, subsequent inspections may consist of external visual inspections of the jacketing in lieu of surface examinations. Tanks with tightly adhering insulation may use the "Alternatives to Removing Insulation" portion of this AMP for initial and all follow-on inspections.

10. A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted prior to the PEO and during each 10-year period during the PEO demonstrates that the absence of environmental impacts in the vicinity of the plant due to: (a) the plant being located within approximately 5 miles of a saltwater coastline, or within 1/2 mile of a highway that is treated with salt in the wintertime, or in areas in which the soil contains more than trace chlorides, (b) cooling towers where the water is treated with chlorine or chlorine compounds, and (c) chloride contamination from other agricultural or industrial sources. The evaluation should include soil sampling in the vicinity of the tank (soil results are indicative of atmospheric fallout accumulating in the soil and potentially impacting tank surfaces) and sampling of residue on the top and sides of the tank to ensure that chlorides or other deleterious compounds are not present at sufficient levels to cause pitting corrosion, crevice corrosion, or cracking.

11. A minimum of either 25 (e.g., 1-square-foot sections for tank surfaces, 1-linear-foot of weld length) or 20 percent of the tank's surface are examined. The sample inspection points are distributed such that inspections occur in those areas most susceptible degradation (e.g., areas where contaminants could collect, inlet and outlet nozzles, welds).

12. When volumetric examinations of the tank bottom cannot be conducted due to the tank being coated, an exception should be stated, and the accompanying justification for not conducting inspections should include the considerations in footnote 13, below, or an alternative examination methodology is proposed.

13. A one-time inspection conducted in accordance with GALL Report AMP XI.M32 may be conducted in lieu of periodic inspections if an evaluation conducted prior to the PEO and during each 10-year period during the PEO demonstrates that the soil under the tank is not corrosive using actual soil samples that are analyzed for each individual parameter (e.g., resistivity, pH, redox potential, sulfides, sulfates, moisture) and overall soil corrosivity. The evaluation should include soil sampling from underneath the tank.

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