Michael P. Gallagher
Vice President, License Renewal
Exelon Nuclear

200 Exelon Way
Kennett Square, PA 19348

610 765 5958 Office
610 765 5956 Fax
www.exeloncorp.com

michaelp.gallagher@exeloncorp.com

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10 CFR 50
10 CFR 51
10 CFR 54

RS-14-003

January 13, 2014

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

Braidwood Station, Units 1 and 2
Facility Operating License Nos. NPF-72 and NPF-77
NRC Docket Nos. STN 50-456 and STN 50-457

Byron Station, Units 1 and 2
Facility Operating License Nos. NPF-37 and NPF-66
NRC Docket Nos. STN 50-454 and STN 50-455

Subject: Response to NRC Requests for Additional Information, Set 2, dated December 13, 2013, related to the Braidwood Station, Units 1 and 2 and Byron Station, Units 1 and 2 License Renewal Application

References:
1. Letter from Michael P. Gallagher, Exelon Generation Company LLC (Exelon) to NRC Document Control Desk, dated May 29, 2013, "Application for Renewed Operating Licenses."
2. Letter from John W. Daily, US NRC to Michael P. Gallagher, Exelon, dated December 13, 2013, "Requests for Additional Information for the Review of the Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2, License Renewal Application – Aging Management, Set 2 (TAC NOS. MF1879, MF1880, MF1881, AND MF1882)

In the Reference 1 letter, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Byron Station, Units 1 and 2, and Braidwood Station, Units 1 and 2 (BBS). In the Reference 2 letter, the NRC requested additional information to support the staffs' review of the LRA.

Enclosure A contains the responses to these requests for additional information.

Enclosure B contains updates to sections of the LRA (except for the License Renewal Commitment List) affected by the responses.

Enclosure C provides an update to the License Renewal Commitment List (LRA Appendix A, Section A.5). There are no other new or revised regulatory commitments contained in this letter.

If you have any questions, please contact Mr. Al Fulvio, Manager, Exelon License Renewal, at 610-765-5936.

I declare under penalty of perjury that the foregoing is true and correct.

Executed on 01-13-2014

Respectfully,

Michael P. Gallagher

Michael P. Gallagher
Vice President - License Renewal Projects
Exelon Generation Company, LLC

Enclosures: A: Responses to Requests for Additional Information
B: Updates to affected LRA sections
C: License Renewal Commitment List Changes

cc: Regional Administrator – NRC Region III
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Senior Resident Inspector, Braidwood Station
NRC Senior Resident Inspector, Byron Station
NRC Project Manager, NRR-DORL-Braidwood and Byron Stations
Illinois Emergency Management Agency - Division of Nuclear Safety

Enclosure A

Byron and Braidwood Stations (BBS), Units 1 and 2
License Renewal Application
Responses to Requests for Additional Information

RAI 3.0.3-1
RAI 3.0.3-2
RAI 3.0.3-3
RAI B.2.1.17-1
RAI B.2.1.17-2
RAI B.2.1.28-1
RAI B.2.1.28-2
RAI B.2.1.28-3
RAI B.2.1.28-4
RAI B.2.1.28-5
RAI B.2.1.23-1
RAI B.2.1.25-1

<u>RAI 3.0.3-1</u>, Recurring internal corrosion (000)

<u>Applicability</u>: Byron Nuclear Station (Byron) and Braidwood Nuclear Station (Braidwood)

<u>Background</u>:

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. One of these issues is 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.

<u>Issue:</u>

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 that has occurred over 3 or more sequential or non-sequential cycles) of aging effects with the same aging mechanism.

b. 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 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), 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 does 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 do not challenge the pressure boundary function of a component.

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.

The staff noted that a separate RAI addresses MIC on the internal surfaces of fire water system piping.

<u>Request:</u>

1. Based on the results of a review of the past 10 years of plant-specific OE, if recurring internal corrosion has occurred, describe each aging effect, its extent, and the AMP that will manage this effect.

2. If recurring internal corrosion has occurred, state the following:

    a. 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.

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

    c. 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).

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

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

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

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

MIC on the internal surfaces of fire water system piping need not be addressed in the response to this RAI.

Exelon Response:

1. Based on the results of a review of the past 10 years of plant-specific operating experience, recurring internal corrosion has occurred in carbon steel portions of the Fire Protection System and Service Water System at Byron and Braidwood. The applicable aging effect is loss of material due to microbiologically-influenced corrosion (MIC). As stated in the *Request*, loss of material due to MIC in the Fire Protection System will not be addressed in this RAI.

   At Byron, between 2001 and 2011, there have been 27 pipe replacements performed to address leakage, wall-thinning, or other flaws in the Service Water System. In 2009, implementation of a raw water corrosion program began at Byron. As a result of the implementation of the raw water corrosion program, additional flushing and inspections have been performed. The additional inspections performed as part of the raw water corrosion program included a guided wave survey of the Service Water System. Since 2011 (i.e., since the raw water corrosion program has been fully implemented), there have been five (5) additional pipe replacements to address leakage and wall-thinning in the Service Water System. Four (4) of the five (5) piping replacements performed since 2011 have been proactive replacements prior to the development of a leak. This provides objective evidence that the preventive measures and monitoring activities performed as part of the raw water corrosion program are effective in managing loss of material due to MIC. These activities will be continued through the period of extended operation as part of the Open-Cycle Cooling Water System (B.2.1.11) aging management program.

   At Braidwood, fewer instances of MIC-related degradation in the Service Water System have been identified during the review of plant-specific operating experience. Between 2001 and 2011, there have been eight (8) pipe replacements performed to address leakage, wall-thinning, or other flaws in the Service Water System. In 2009, implementation of a raw water corrosion program began at Braidwood. Since MIC in the Service Water System at Braidwood is less extensive than at Byron, the implementation of the raw water corrosion program at Braidwood lags that at Byron. However, as a result of the implementation of the raw water corrosion program, additional flushing and inspections have been performed. Although guided wave inspections of portions of the Service Water System have been performed, a guided wave survey of the entire Service Water System has not yet been performed at Braidwood. Since 2011, there has been one (1) additional pipe replacement to address leakage and wall-thinning in the Service Water System. The reduction in the number pipe replacements that have been required provides objective evidence that the preventive measures and monitoring activities performed as part of the raw water corrosion program are effective in managing loss of material due to MIC. These activities will be continued through the period of extended operation as part of the Open-Cycle Cooling Water System (B.2.1.11) aging management program.

   The Open-Cycle Cooling Water System (B.2.1.11) aging management program will manage loss of material due to MIC in the Service Water System. The Open-Cycle Cooling Water System (B.2.1.11) aging management program credits the existing activities performed in accordance with the station commitments to the requirements of GL 89-13 (i.e., GL 89-13 program) as augmented by additional activities performed in accordance with the station's raw water corrosion program. The raw water corrosion program activities include inspections and preventive measures (e.g., flushing, biocide injection).

The existing mitigation and monitoring activities have been effective in managing MIC in the Service Water System as demonstrated by the fact that neither MIC induced pipe leaks nor pipe wall thinning, including the consideration of structural integrity, has resulted in the loss of a component's ability to support system pressure and flow requirements. In addition, MIC induced leakage from piping has not resulted in the loss of any safety function of nearby safety-related equipment. Therefore, the performance of the aging management activities described above, as required by the Open-Cycle Cooling Water System (B.2.1.11) aging management program, provides reasonable assurance that the Service Water System intended functions will be maintained consistent with the current licensing basis through the period of extended operation.

2a. The Open-Cycle Cooling Water System (B.2.1.11) aging management program relies on ultrasonic testing (UT) of Service Water System piping to detect and monitor locations where loss of material due to MIC is occurring such that repairs or replacements are performed prior to loss of intended function. Ultrasonic testing is an industry accepted and recognized method for detecting loss of material due to MIC prior to loss of component intended function. The Open-Cycle Cooling Water System (B.2.1.11) aging management program is augmented to utilize a 100% scan UT method rather than a point-to-point grid UT method to ensure that the localized MIC aging mechanism is detected. The inspections required by this program are performed at locations that are chosen to be leading indicators of the material condition of the internal surface of components within the scope of the program. The specific locations for inspections are chosen based on commitments made in the Byron and Braidwood responses to NRC GL 89-13, piping configuration, flow conditions (e.g., stagnant or low flow areas), and operating history (e.g., prior inspection results). The maximum interval for re-inspection is based on the calculated remaining life of the component. If required, piping replacement is performed prior to the development of through-wall leakage. Therefore, the inspections performed in accordance with the Open-Cycle Cooling Water System (B.2.1.11) aging management program are sufficient to ensure that intended functions will be maintained consistent with the current licensing basis through the period of extended operation. The Byron and Braidwood LRA Appendix A, Section A.2.1.11, and Appendix B, Section B.2.1.11, are revised to reflect the augmented aging management activities described above, as shown in Enclosure B of this letter.

2b. The Byron and Braidwood Open-Cycle Cooling Water System (B.2.1.11) aging management program relies on inspections performed in accordance with the commitments made in the Byron and Braidwood responses to NRC GL 89-13. The BBS Generic Letter (GL) 89-13 program is augmented by additional activities, including UTs, performed as part of the raw water corrosion program. The raw water corrosion program was developed to address plant-specific and industry operating experience. The raw water corrosion program implements appropriate corrective actions and industry best practices (e.g., 100% scan UT method rather than point-to-point, additional inspections, additional flushing) to address plant-specific operating experience. The Open-Cycle Cooling Water System (B.2.1.11) aging management program credits the combined aging management activities performed by the GL 89-13 program and the raw water corrosion program to ensure aging effects in the Service Water System are adequately managed. As described above, recent plant-specific operating experience indicates that the implementation of the raw water corrosion program (beginning in 2009) has been effective at detecting and preventing MIC prior to loss of system intended function.

The approach described above is consistent with the recommendations in GALL Report program XI.M20, Open-Cycle Cooling Water System. As stated in element 10, significant MIC issues were considered in the NRC guidance provided in GALL Report program XI.M20. As further stated in element 10 of GALL Report program XI.M20, the guidance of NRC GL 89-13 has been implemented for more than 20 years and has been effective in managing aging, including loss of material due to MIC, of open-cycle cooling water systems. Finally, as stated in element 7 of GALL Report program XI.M20, the 10 CFR Part 50, Appendix B corrective action program is an appropriate mechanism to develop an action plan to address deficient conditions.

The existing mitigation and monitoring activities have been effective in managing MIC in the Service Water System as demonstrated by the fact that neither MIC induced pipe leaks nor pipe wall thinning, including the consideration of structural integrity, has resulted in the loss of a component's ability to support system pressure and flow requirements. MIC induced leakage from piping has not resulted in the loss of any safety function of nearby safety-related equipment.

The BBS Open-Cycle Cooling Water System (B.2.1.11) aging management program credits activities related to the commitments to GL 89-13 as augmented by the raw water corrosion program. These activities have been shown to be effective in ensuring that Service Water System intended functions are maintained based on a review of plant-specific operating experience. Therefore, continuation of these aging management activities through the period of extended operation provides reasonable assurance that Service Water System intended functions will be maintained consistent with the current licensing basis.

2c. Wall-thinning of piping within the scope of this program is the parameter that is monitored and trended. Evidence of wall-thinning due to corrosion, including MIC, in the Service Water System is documented in the applicable BBS work orders and degraded conditions are entered into the BBS corrective action program for corrective action and disposition. The subsequent evaluation of these conditions includes an assessment for impact on the integrity of the piping. As part of this assessment, wall-thinning is trended by determining material loss rate and remaining life of the piping. The 10 CFR Part 50 Appendix B corrective action program is relied upon to determine appropriate corrective actions if evidence of age-related degradation of Service Water System piping is identified. Evaluations of degraded conditions performed as part of the corrective action program will consider extent of degradation in determining appropriate corrective actions (e.g., additional inspections, increased inspection frequency, repair or replacement). Specific guidance in raw water corrosion program procedures requires additional inspections in locations of similar flow and configuration if wall loss greater than 50% is identified or if remaining life of less than 2 years is calculated.

2d. For Byron, the Open-Cycle Cooling Water System (B.2.1.11) aging management program credits existing periodic UTs on 29 piping segments to detect loss of material due to MIC in the Service Water System. For Braidwood, the Open-Cycle Cooling Water System (B.2.1.11) aging management program credits existing periodic UTs on 26 piping segments to detect loss of material due to MIC in the Service Water System (note that multiple locations are inspected on some of the 26 piping segments). The UTs required by this program utilize a 100% scan method to ensure that localized corrosion, characteristic of MIC, is identified. The specific inspection locations have been chosen based on the following: (1) commitments to GL 89-13, (2) piping configuration, (3) flow conditions, and (4) operating history. At Byron, a guided wave survey of Service Water System piping has been performed and is utilized as an input in selecting specific locations for UTs. A plan to perform a similar guided wave survey at Braidwood is in place and the results of this future activity may be used to determine locations of future UTs.

The maximum interval for re-inspection is based on the results of previous inspections. If the UTs required by the Open-Cycle Cooling Water System (B.2.1.11) aging management program identify degraded conditions then the remaining life of the component is calculated and, if applicable, the inspection scope is expanded. For locations where degraded conditions are identified, the re-inspection interval is chosen to ensure that re-inspection is performed prior to the component reaching the calculated end-of-life based on the corrosion rate and minimum wall thickness requirements. The approach described above provides reasonable assurance that intended functions will be maintained consistent with the current licensing basis through the period of extended operation.

2e. Portions of the Service Water System that are within the scope of license renewal are buried or underground at Byron and Braidwood. As described in the response to RAI B.2.1.28-5, the buried portions of the Service Water System are mostly (95% at Byron) or entirely (100% at Braidwood) encased in concrete or back-filled in cementitious controlled low strength material (CLSM), making these portions of the system inaccessible for ultrasonic testing. However, loss of material due to MIC is more likely to occur in stagnant/low flow areas. The buried portions of the Service Water System within the scope of license renewal are either subjected to constant flow or intermittent high flow and, as such, MIC is unlikely to occur. The inspections performed in accordance with the Open-Cycle Cooling Water System (B.2.1.11) aging management program are performed at locations that are chosen to be leading indicators of the material condition of the internal surface of the Service Water System. Therefore, since inspections are performed on aboveground portions of the system where degradation is most likely to occur, the results of the inspections of these locations bound the condition of the inaccessible buried portions of the system. In addition, pinhole leaks in buried piping due to MIC, should they occur, are unlikely to prevent the Service Water System from providing sufficient flow at adequate pressure. Therefore, direct inspections of buried portions of the Service Water System are not required.

Regardless, at Byron, guided wave collars have been installed at ten locations to allow for periodic monitoring and trending for potential loss of material, including loss of material due to MIC, in buried and underground portions of the Service Water System. At Braidwood, guided wave inspections of portions of the buried portions of the Service Water System have been performed in the past and no indication of significant degradation has been identified.

2f. Although underground leaks are possible, leaks large enough to affect the function of the Service Water System 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, or by the appearance of wetted ground around the areas of leaks.

2g. As a result of RAI 3.0.3-1, the Byron and Braidwood Open Cycle Cooling Water program, described in LRA Appendix A, Section A.2.1.11, and Appendix B, Section B.2.1.11, is revised as shown in Enclosure B of this letter to reflect the augmented aging management activities described in response to request 2a.

<u>RAI 3.0.3-2</u>, Loss of coating integrity for Service Level III and Other coatings (000)

<u>Applicability</u>: Byron and Braidwood

<u>Background</u>:

Recent industry OE and questions raised during the staff's review of several LRAs have resulted in the staff concluding that several AMP and AMR items in the LRA may not or do not account for this OE. One of these issues is 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, increased pressure drop, reduction in heat transfer) due to flow blockage. Based on these industry OE examples, the staff has questions related to how the 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 interiors of in-scope piping, heat exchangers, and tanks which support functions identified under 10 CFR 54.4(a)(1) and (a)(2).
b. "Other coatings" includes coatings installed on the interiors 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.

<u>Issue</u>:

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

a. Baseline visual inspections of coatings installed on the interior surfaces of in-scope components.
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, yet a coating specialist has determined that no remediation is required, then 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 each of 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 ASTM International standard endorsed in RG 1.54, "Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants," including staff guidance associated with a particular standard.

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.

Request:

1. 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. Consider such factors as whether coatings can be verified to have been installed to manufacturer specifications, prior inspection findings of acceptable or degraded coatings, and coating replacement history.
    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.
    i. The program(s) that will be augmented to include the above requirements.
2. State how LRA Section 3 Table 2s, Appendix A, and Appendix B will be revised to address the program(s) used to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage.

Exelon Response:

In response to this RAI a review was performed to identify the components with internal coatings that are within the scope of license renewal. Based on this review, the in-scope components with internal coatings include:

(1) Specific heat exchangers cooled by the Service Water System
(2) Emergency diesel generator fuel oil storage tanks
(3) Foam concentrate tanks in the Fire Protection System
(4) Galvanized portions of the Fire Protection System
(5) Lined lubricating oil reservoirs
(6) Components associated with the caustic and acid supply to the Radwaste System demineralizers (not in service)
(7) Components associated with hypochlorite injection to the discharge of the essential service water pumps (not in service)
(8) 0C Auxiliary Building chiller condenser at Byron (not in service)

Items (4) through (8) do not require visual inspections to prevent or mitigate unanticipated or accelerated corrosion of the base metal and/or degraded performance of downstream equipment due to flow blockage (e.g., reduction in flow, increased pressure drop, reduction in heat transfer) as described in the following paragraphs:

For item number (4): The Fire Protection System includes galvanized piping associated with carbon dioxide-based fire suppression subsystems and water-based fire suppression subsystems (including foam subsystems). Piping associated with the carbon dioxide-based fire suppression subsystems is not expected to degrade regardless of the condition of the galvanized coating since it is a dry system. Loss of coating integrity causing degraded performance of downstream equipment due to flow blockage is not expected to occur for galvanized piping in a dry gas environment. Regardless, the Fire Protection (B.2.1.15) aging management program includes flow testing of the carbon dioxide-based fire suppression subsystems to verify the absence of blockage due to coating failure or any other applicable mechanism.

Galvanized piping associated with the water-based fire suppression subsystems is susceptible to age-related degradation. However, galvanized piping is not subject to unanticipated or accelerated corrosion of the base metal due to coating holidays. The unanticipated or accelerated aging postulated in the *Background* section of this RAI is valid for most non-sacrificial coating systems since the coating forms a large cathode that is coupled with a small anode where a coating holiday exists. As described in *Corrosion Engineering*, Third Edition (M. A. Fontana), a large cathode surface and a small anode surface (e.g., due to a coating holiday) forms a strong galvanic cell (in an aqueous solution) that leads to accelerated corrosion of the smaller anode. However, in the case of galvanized steel, since zinc has a lower electrode potential than steel, the roles are reversed, with the zinc coating acting as a large sacrificial anode coupled with a small cathode where the steel substrate is exposed in the coating holiday. In certain specific situations (e.g., high temperatures) the galvanized coating can act as an anode but those situations do not exist in the Fire Protection System. Since there is a relatively small cathode surface and a relatively large anode surface, there is no accelerated corrosion. In fact, the remaining zinc acts as a sacrificial anode to the base metal and provides cathodic protection for the exposed surfaces of the piping for a long period of time, which is why galvanizing is the standard method of corrosion mitigation in steel. Therefore, galvanized piping is not subject to accelerated corrosion of the base metal due to coating holidays.

In addition, degraded performance of downstream equipment due to flow blockage is not expected to occur for galvanized piping since the zinc coating dissolves into solution as it degrades and does not delaminate, blister, crack, flake, or peel. Regardless, the Fire Water System (B.2.1.16) aging management program includes flow testing of water-based fire suppression subsystems to verify the absence of blockage due to coating failure or any other applicable mechanism.

For item number (5): The lubricating oil reservoirs for certain pumps at Byron and Braidwood have internal linings. The aging of these reservoirs, including the internal linings, is managed by the Lubricating Oil Analysis (B.2.1.26) aging management program. The Lubricating Oil Analysis (B.2.1.26) aging management program includes oil sampling and oil change activities that are capable of detecting coating degradation. The oil sampling associated with the Lubricating Oil Analysis (B.2.1.26) aging management program includes testing for particulate in the oil which would indicate degradation of the internal lining of the reservoir or of the base metal. Since the Lubricating Oil Analysis (B.2.1.26) aging management program includes activities capable of detecting lining degradation prior to loss of intended function, no additional inspections of the internal linings of the lubricating oil reservoirs are warranted.

For items number (6), (7), and (8): These SSCs are either no longer in service or were never in service and, therefore, are not exposed to the aggressive internal environment for which the coating was required. In the unlikely event that the coating/lining becomes disbonded from the base metal, degraded performance of downstream equipment is not possible since the system is stagnant and there is a closed valve between the lined/coated components and in-service equipment downstream. The recommendations for managing age-related degradation of internal coatings or linings described in the *Issue* of this RAI are not appropriate for the internal coatings or linings of components that are not in service. Visual inspections of these SSCs performed in accordance with the requirements of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) aging management program will include assessment of the condition of the internal coatings or linings. As a result of RAI 3.0.3-2, LRA Sections A.2.1.25 and B.2.1.25 are revised as shown in Enclosure B.

For items (1), (2), and (3), visual inspections are required to manage loss of coating integrity due to blistering, cracking, flaking, peeling, or physical damage of Service Level III and other coatings. Visual inspections of components with internal coatings within the scope of license renewal will be performed as follows:

1a. Visual inspections are performed as part of the appropriate aging management programs for the applicable systems, as identified in the response to 1c.

1b. Internal coatings are visually inspected for signs of coating failures and precursors to coating failures including erosion, cracking, flaking, peeling, blistering, delamination, rusting, and mechanical damage.

1c. Existing visual inspection activities for coatings will continue through the period of extended operation as part of the Open-Cycle Cooling Water System (B.2.1.11) aging management program (specific heat exchangers cooled by the Service Water System), the Fuel Oil Chemistry (B.2.1.18) aging management program (emergency diesel generator fuel oil storage tanks), and the Fire Water System (B.2.1.16) aging management program (foam concentrate tanks).

Inspections of coated heat exchangers cooled by the Service Water System are performed every two (2) to six (6) years, depending on the heat exchanger, and will continue through the period of extended operation. The inspection frequency for individual heat exchangers is based on the criticality of the component, prior inspection results, and service conditions.

Inspections of the diesel oil storage tank coatings will be performed at least once during the 10-year period prior to the period of extended operation, and at least once every 10 years during the period of extended operation as part of the visual inspections of the internal surface of the diesel oil storage tanks required by the Fuel Oil Chemistry (B.2.1.18) aging management program. The 10-year inspection frequency is consistent with the guidance provided in EPRI TR-1019157, *Guideline on Nuclear Safety-Related Coatings*, Revision 2.

The foam concentrate tanks are coated steel tanks with an internal bladder that contains the foam concentrate. Due to this design it is not possible for failed coatings to result in degraded performance of downstream equipment due to flow blockage as long as the bladder remains intact. Inspections of the coatings for the foam concentrate tanks are performed every 15 years during replacement of the internal bladder. This inspection frequency is appropriate based on the consequence of coating degradation and prior inspection results.

1d. 100% of coated surfaces that are accessible upon component disassembly or entry are visually inspected during each inspection interval.

1e. Inspections of Service Level III coatings are performed by individuals certified to ANSI N45.2.6, *Qualifications of Inspection, Examination, and Testing Personnel for Nuclear Power Plants*. Inspection reports are provided to the site coatings coordinator. The site coatings coordinator will be qualified in accordance with ASTM D 7108-05, *Standard Guideline for Establishing Qualifications for a Nuclear Coating Specialist*, as described in the Protective Coating Monitoring and Maintenance Program (B.2.1.36).

Inspections of Service Level II coatings are performed by system managers or maintenance personnel utilizing procedural guidance. Personnel performing inspections are qualified in accordance with the INPO National Academy for Nuclear Training accredited training program that meets industry standards described in ACAD 92-008, “Guidelines for Training and Qualification of Maintenance Personnel”. Less stringent qualification requirements for nonsafety-related Service Level II coatings are appropriate based on favorable plant-specific operating experience and the reduced impact of potential consequences of coating degradation.

1f. The as-found condition of the coating is documented in inspection reports. The results of previous inspections are used to determine changes in the condition of the coating over time. Trending of coating degradation is utilized to establish appropriate inspection frequencies for components with internal coatings. The frequency of coating inspections is based, in part, on the results of prior inspections. These frequencies are chosen such that coating degradation is identified before degradation of the base metal occurs such that intended functions of the coated component are maintained.

1g. Inspections are performed for signs of coating failures and precursors to coating failures including erosion, cracking, flaking, peeling, blistering, delamination, rusting, and mechanical damage. Any loss of coating integrity such that loss of material of the base metal occurs is considered a coating failure. Localized areas of loss of coating integrity without subsequent loss of material of the base metal are considered acceptable. Plant-specific operating experience has shown that this acceptance criteria is adequate to ensure the intended function(s) of the coated components, and, if applicable, downstream components, are maintained.

1h. Evaluations are performed for inspection results that do not satisfy established criteria and the conditions are entered into the BBS 10 CFR 50 Appendix B corrective action program (CAP). The corrective action program ensures that conditions adverse to quality are promptly corrected. If appropriate, corrective actions may include coating repair prior to the component being returned to service.

1i. The Open-Cycle Cooling Water System (B.2.1.11) aging management program, Fire Water System (B.2.1.16) aging management program, and Fuel Oil Chemistry (B.2.1.18) aging management program are revised as shown in Enclosure B of this response.

2. LRA Sections 3.2.2.1.4, 3.3.2.1.12, 3.3.2.1.15, 3.3.2.1.20, 3.3.2.1.22, and 3.4.2.1.1; and LRA Tables 2.3.3-22, 3.2.2-4, 3.3.2-12, 3.3.2-15, 3.3.2-20, 3.3.2-22, and 3.4.2-1 are revised as shown in Enclosure B to identify systems and components with internal linings or coatings. In addition, LRA Appendix A Sections A.2.1.11, A.2.1.16, A.2.1.18, A.2.1.25, and A.2.1.26; and LRA Appendix B Sections B.2.1.11, B.2.1.16, B.2.1.18, B.2.1.25, and B.2.1.26 are revised as shown in Enclosure B to identify the aging management activities that will be performed to manage loss of coating integrity for in scope SSCs with internal coatings or linings.

RAI 3.0.3-3, Corrosion under insulation (000)

Applicability: Byron and Braidwood

Background:

Recent industry OE and questions raised during the staff's review of several LRAs have resulted in the staff concluding that several AMP and AMR items in the LRA may not or do not account for this OE. One of these issues is corrosion under insulation (CUI).

During a recent license renewal AMP audit, the staff observed extensive general corrosion (i.e., extent of corrosion from a surface area, but not depth of penetration, perspective) underneath the insulation removed from an auxiliary feedwater (AFW) suction line. The process fluid temperature was below the dew point for a period of time sufficient 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 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 examinations of the surfaces under insulation.

Issue:

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

a. Periodic inspections should be conducted during each 10-year period of the PEO.
b. For a representative sample of outdoor components (except tanks) and for 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 should be 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. Sample inspection points should be distributed such that inspections occur on the tank domes, sides, near the bottoms, 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.

   ii. No evidence of stress corrosion cracking (SCC).

If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g. water seepage through insulation seams/joints), then periodic inspections under the insulation should continue as described above.
The staff notes that a separate RAI addresses CUI for insulated condensate storage tanks (CSTs).

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

CUI for the CSTs need not be addressed in the response to this RAI.

Exelon Response:

As described in NACE Standard SP0198-2010, "Control of Corrosion Under Thermal Insulation and Fireproofing Materials – A Systems Approach," corrosion under insulation (CUI) can occur due to the presence of moisture on the external surface of insulated components. The presence of moisture is due to either the infiltration of water from external sources or condensation on the surface of the component. Infiltration of water from external sources is assumed to occur for all insulated components located outdoors and exposed to rainfall and other environmental sources of water. Condensation on the external surface of insulated components located indoors can occur when the temperature of the metal surface is lower than the atmospheric dew point for a sufficient period of time. Therefore, the presence of moisture, on the external surface of insulated components located outdoors and insulated components located indoors that operate below the dew point, is assumed. As such, the loss of material aging effect will be managed for the external surfaces of these components.

As further described in NACE SP0198-2010, stress corrosion cracking (SCC) of stainless steel can occur when halides are transported in the presence of water to the hot surface of components and then concentrated by the evaporation of that water. The sources of halides fall in two (2) categories. First, halides may be present due to leachable halides in insulating materials. SCC due to contamination from leachable halides typically occurs after only a few years. A review of operating experience did not indicate any instances of SCC due to leachable halides in insulating materials. A review of the insulation specification and procedures indicates that insulating materials with leachable halides are not used at Byron and Braidwood on components within the scope of this response. Second, halides may be present due to external sources (e.g., rain, fog, deicing salt). As described in revised LRA Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2, SCC due to halide contamination from environmental sources is not expected to occur for insulated components. In addition, the in scope insulated components located outdoors do not operate at high temperatures where concentration of environmental halides is expected to occur due to the evaporation of any moisture that is present. Therefore, cracking due to SCC is not credible for insulated stainless steel components located outdoors or insulated stainless steel components located indoors that operate below the dew point. As such, periodic visual inspections of insulated stainless steel components will be performed to detect loss of material, as described below, but volumetric or surface examinations to detect cracking due to SCC are not required.

The following LRA Section 3 tables are revised to address the management of the aging effects as described above: 3.2.1 (Engineered Safety Features), 3.3.1 (Auxiliary Systems), and 3.4.1 (Steam and Power Conversion). Plant specific notes are added to the following Section 3 tables to address the management of the aging effects as described above: 3.2.2-4 (Safety Injection System), 3.3.2-1 (Auxiliary Building Ventilation System), 3.3.2-2 (Chemical & Volume Control System), 3.3.2-3 (Chilled Water System), 3.3.2-11 (Emergency Diesel Generator & Auxiliary System), 3.3.2-12 (Fire Protection System), 3.3.2-22 (Service Water System), and 3.4.2-3 (Main Condensate and Feedwater System).

LRA Section 3, Table 2 line items, are added which credit the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program, and include the addition of in-scope insulated components located indoors where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope insulated components located outdoors. The following tables are revised to add the line items described above: 3.2.2-4 (Safety Injection System), 3.3.2-1 (Auxiliary Building Ventilation System), 3.3.2-2 (Chemical & Volume Control System), 3.3.2-3 (Chilled Water System), 3.3.2-12 (Fire Protection System), 3.3.2-22 (Service Water System), 3.4.2-1 (Auxiliary Feedwater System), and 3.4.2-3 (Main Condensate and Feedwater System).

The following tables contained in LRA Section 2 are revised to add insulated components: 2.3.2-4 (Safety Injection System), 2.3.3-1 (Auxiliary Building Ventilation System), 2.3.3-2 (Chemical & Volume Control System), 2.3.3-3 (Chilled Water System), 2.3.3-12 (Fire Protection System), 2.3.3-22 (Service Water System), 2.3.4-1 (Auxiliary Feedwater System), and 2.3.4-3 (Main Condensate and Feedwater System).

Section 3.3.2.1.22 is revised to show that condensation is an applicable environment for the Service Water System at Braidwood as well as Byron.

The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be revised to include the following:

a. Periodic inspections to identify corrosion under insulation or subsequent insulation examinations, if applicable, will be conducted during each 10-year period of the period of extended operation.

b. For a representative sample of in-scope outdoor components (except outdoor insulated tanks which are addressed in response c below) and for any indoor components operated below the dew point (except indoor insulated tanks which are addressed in response c below), remove the insulation and inspect a minimum of 20 percent of the in-scope piping length for each material type, 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 should be conducted in each environment (e.g., air-outdoor, condensation) where condensation or moisture on the surfaces of the component could occur routinely or seasonally.

c. For a representative sample of in-scope indoor insulated 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. Sample inspection points will be distributed such that inspections occur on the tank domes, sides, near the bottoms, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects, such as on top of stiffening rings. With the exception of the condensate storage tanks, which are not addressed in this RAI response, there are no in-scope outdoor insulated tanks.

d. Inspection locations will be based on the likelihood of CUI occurring. Factors such as alternate wetting and drying in environments where trace contaminants could be present, and length of time the system operates below the dew point, will be included in the selection of inspection locations.

e. Removal of tightly-adhering insulation that is impermeable to moisture will not be 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 and, therefore, insulation will not be removed. The entire accessible population (i.e., 100%) of in-scope piping that has tightly-adhering insulation will be visually inspected for damage to the moisture barrier during each 10-year period of the period of extended operation. Tightly-adhering insulation will be considered to be a separate population from the remainder of insulation installed on in-scope components. These inspections will not be credited towards the inspection quantities for other types of insulation described above in response b.

f. Subsequent inspections of in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation when the following conditions are verified in the initial inspection:

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

   ii. As described in the response to this RAI, cracking due to stress corrosion cracking is not an applicable aging effect for insulated stainless steel components located outdoors or insulated stainless steel components located indoors that operate below the dew point at Byron and Braidwood.

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

The condensate storage tanks are not addressed in this RAI response.

Based on the above, the External Surfaces Monitoring of Mechanical Components (B.2.1.23) program is revised to address CUI for indoor insulated components, operated below the dew point, and outdoor insulated components. LRA Appendix A.2.1.23 and LRA Appendix B.2.1.23 are revised as shown in Enclosure B. LRA Table A.5 Item 23 is revised as shown in Enclosure C.

<u>RAI B.2.1.17-1</u>, Corrosion under insulation for condensate storage tanks (030)

<u>Applicability</u>: Byron and Braidwood

<u>Background</u>:
The exception in LRA Section B.2.1.17, "Aboveground Metallic Tanks," states, "[t]he lagging and insulation will be removed on a sample basis to demonstrate that the lagging, roof flashing, insulation, and the sealant are effective in preventing moisture intrusion and in preventing significant loss of material to the aluminum tank [condensate storage tanks (CST)] external surface." GALL Report AMP XI.M29, "Aboveground Metallic Tanks", infers that the entire external surface of a tank is visually inspected; however, it does not address insulated tanks. During the audit, the staff noted that the sampling basis for removal of insulation has been defined as removing the tank insulation from 4 1-square-foot locations equidistant around the tank circumference at the base of each tank and from 4 1-square-foot locations equidistant 18 inches above the tank base and offset from the lower inspections.

As stated in the "operating experience" program element in the LRA, both CSTs at both stations had either lost jacketing integrity and/or water was noted at the base of the tank from rain water penetrating down between the jacketing, insulation, and the tank's outside surface. During the audit, the staff noted that the tank insulation consists of foam glass® insulation and fiberglass insulation.

<u>Issue</u>:
During the AMP Audit, the staff noted that the CSTs have several attachments (e.g., instruments, heaters, ladders) that penetrate the insulation and jacketing. The penetrations represent locations of higher susceptibility to rain water intrusion, and therefore, inspection locations should be selected accordingly.

The staff lacks sufficient information to conclude that the foam glass® and fiberglass insulation is chloride and halide free as supplied in its product form. Chlorides and halides could cause pitting and cracking in aluminum tanks. Recommended acceptable levels of chlorides and halides are described in Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steels," February 1973.

At Byron, the cooling towers are treated with a chlorine-based chemical. At Braidwood, an apparent cause evaluation of leaks in buried fire protection piping states that, for a segment of stainless steel piping, LS-AA-125-1003, "[w]here the coating was disbonded, severe external pitting was identified, which included the location of the leak." This indicates the potential for chloride or halides to be present in the soil and atmosphere at Braidwood.

Based on the potential for chloride and halide contamination from the atmosphere or tank insulation and previous in-leakage past the insulation jacketing, it is not clear to the staff that inspecting 16 1-square-foot locations (including both CSTs) will be adequate to provide reasonable assurance that the CSTs' current licensing basis intended functions will be met during the period of extended operation. In addition, if chlorides or halides are present, visual inspections may not be sufficient to detect cracking. Further, if cracking could be an applicable aging effect, the "acceptance criteria" program element should have acceptance criteria for cracks.

Request:

1. State whether the locations where insulation will be removed will include locations below penetrations through the insulation and its jacketing. If not, state the basis for how the inspection locations will represent those with the highest likelihood of aging effects.
2. State whether the foam glass® and fiberglass insulation contain low enough levels of chlorides and halides such that they will not result in pitting and cracking on the aluminum tank surfaces.
3. State how it will be determined that the environment in the vicinity of the CSTs contain low enough levels of chlorides and halides such that they will not result in pitting and cracking on the aluminum tank surfaces.
4. If the insulation or environment in the vicinity of the CSTs contain high enough levels of chlorides and halides such that they could result in pitting and cracking on the aluminum tank surfaces, state the basis for why 16 inspections will be sufficient to provide reasonable assurance that pitting and cracking will not result in a loss of intended function(s) during the period of extended operation.
5. If cracking is an applicable aging effect, state what inspection methods will be used to detect cracking and the acceptance criteria for cracks.

Exelon Response:

1. The Aboveground Metallic Tanks aging management program (B.2.1.17) did not specifically address performing inspections of the tank external surface below penetrations. The program will be revised such that inspections of the tank external surface will include four 1-foot square locations where insulation will be removed below penetrations through the insulation and its jacketing. As a result of this change, LRA Sections A.2.1.17 and B.2.1.17 are revised to reflect the changes as shown in Enclosure B. The Byron and Braidwood LRA Table A.5 Commitment List, Item 17, is also revised as shown in Enclosure C.

2. Foamglas® insulation conforms to the requirements of Regulatory Guide 1.36, “Nonmetallic Thermal Insulation for Austenitic Stainless Steels,” February 1973. The specific brand of fiberglass insulation installed on the CSTs could not be identified. Therefore, although unlikely, it is conservatively assumed that leachable halide levels are above the levels described in Regulatory Guide 1.36.

3. As described in LRA Section 3.4.2.2.2 (as revised by RAI B.2.1.23-1), cracking due to stress corrosion cracking caused by contamination from environmental halide sources is not expected to occur for insulated components. However, since the halide content of the fiberglass insulation for the CST could not be quantified, pitting and cracking of the aluminum tank surface will be considered as applicable aging effects As a result of this change, LRA Table 3.4.2-3 and Sections A.2.1.17 and B.2.1.17 are revised to reflect the changes as shown in Enclosure B. The Byron and Braidwood LRA Table A.5 Commitment List, Item 17, is also revised as shown in Enclosure C.

4. Given that loss of material due to pitting and cracking due to stress corrosion cracking on the aluminum tank surfaces of the CST are applicable aging effects/mechanisms, the program scope will be revised. Specifically, the sample size will be increased from 16 inspection locations to 25 inspection locations for both tanks combined per site. Sample inspection points will be distributed such that inspections will occur on the tank dome, sides, near the bottom, and at points below penetrations where equipment (e.g. instrument nozzles, tank heaters, ladder) penetrates the insulation. As a result of this change, LRA Sections A.2.1.17 and B.2.1.17 are revised to reflect the changes as shown in Enclosure B. The Byron and Braidwood LRA Table A.5 Commitment List, Item 17, is also revised as shown in Enclosure C.

5. A modification to the commitment for the Aboveground Metallic Tanks aging management program will be made to include a liquid penetrant examination to detect cracking of the tank surface where the 25 inspections are being performed during each 10-year period starting 10 years prior to the period of extended operation. The acceptance criteria shall be in accordance with Appendix 8 of the 2013 ASME Boiler and Pressure Vessel Code, Section VIII which is suitable for this location. As a result of this change, LRA Sections A.2.1.17 and B.2.1.17 are revised to reflect the changes as shown in Enclosure B. The Byron and Braidwood LRA Table A.5 Commitment List, Item 17, is also revised as shown in Enclosure C.

RAI B.2.1.17-2, Age-related degradation inspections for tanks (030)

Applicability: Byron and Braidwood

Background:
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 conditions adverse to quality and the continued aging of the tanks indicate a need to ensure that internal tank inspections are conducted throughout the PEO. In addition, the staff has identified indoor tanks with external stress corrosion cracking that, except for its location, would normally be addressed by GALL Report AMP XI.M29.

Issue:
Based on the industry OE, in regard to the recommendations in GALL Report XI.M29:

a. Based on industry OE, the staff believes that some indoor tanks should have internal inspections. These include indoor welded storage tanks that meet all of the following criteria:
    - have a large volume (i.e., greater than 100,000 gallons)
    - are designed to near-atmospheric internal pressures
    - sit on concrete
    - are exposed internally to water
b. During the AMP audit the staff could not conclude that there were no indoor tanks meeting the above criteria.
c. Periodic inspections should be conducted of the tank's bottom surface (i.e., each 10-year period starting 10 years before the period of extended operation) unless there is a basis for conducting a one-time inspection. The basis could be established based on soil sampling demonstrating that the soil under the tank is not corrosive or that the bottom of the tank is cathodically protected.

   The staff noted that the applicant has proposed to conduct tank bottom ultrasonic inspections within 5 years prior to entering the period of extended operation, between years 5 and 10 of the period of extended operation, and whenever a tank is drained.

Request:

1. If there are any in-scope indoor welded storage tanks that meet all of the above criteria, state whether the tank(s) will be included in the scope of the Aboveground Metallic Tanks, or state the basis for why there is reasonable assurance that the tank(s)' current licensing basis intended function(s) will be met throughout the PEO.
2. State the basis for why conducting tank bottom ultrasonic inspections within 5 years prior to entering the period of extended operation, between years 5 and 10 of the PEO, and whenever a tank is drained is sufficient to provide reasonable assurance that the tank(s)' current licensing basis intended function(s) will be met throughout the PEO.

Exelon Response:

1. A review of all in-scope indoor welded storage tanks was conducted to determine if any of the tanks meet all four of the following criteria:

    - have a large volume (i.e., greater than 100,000 gallons)
    - are designed to near-atmospheric internal pressures
    - sit on concrete
    - are exposed internally to water

    As a result of the review, it was determined that no in-scope indoor welded storage tanks meet all four of the criteria, and therefore, no additional tanks are included in the scope of the Aboveground Metallic Tanks aging management program .

2. As noted in the Issue section of this RAI, periodic inspections should be conducted of the tank's bottom surface unless there is a basis for conducting a one-time inspection. The aging management strategy is revised to conduct one-time ultrasonic inspections of the aluminum condensate storage tank (CST) bottoms (one tank per station) based on the CST bottoms being cathodically protected. The CSTs at Byron and Braidwood Stations are the only tanks within the scope of LRA AMP B.2.1.17, "Aboveground Metallic Tanks." In lieu of conducting CST bottom ultrasonic inspections within 5 years prior to entering the period of extended operation, between years 5 and 10 of the period of extended operation, and whenever a tank is drained, as described in the LRA, one-time ultrasonic inspections of the CST bottoms (one tank per station) will be conducted within the 5-year period prior to the period of extended operation. To ensure the bottom of the tank has an effective cathodic protection system in mitigating corrosion, evaluation of the effectiveness will be based on LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks',". The Aboveground Metallic Tanks aging management program is revised to require that the cathodic protection availability (i.e., at least 85%) and effectiveness (i.e., at least 80%) criteria in Table 4c, footnotes 3.ii and 3.iii, respectively, of LR-ISG-2011-03 be met commencing 5 years prior to the PEO and during the PEO.

    LRA Sections A.2.1.17 and B.2.1.17 are revised to reflect the changes discussed above, and are included in Enclosure B. LRA Table A.5, License Renewal Commitment List, Item 17, is revised to reflect the changes discussed above, and is included in Enclosure C.

RAI B.2.1.28-1, Carbon Steel Piping and Piping Components Exposed to Concrete (035)

Applicability: Byron and Braidwood

Background:

The program description of the Buried and Underground Piping program in the LRA states that the program manages the external surface aging effects for buried and underground piping. 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," "scope of program" program element recommends the same scope. However, LRA Table 3.3.2-22 states that carbon steel piping and piping components exposed to concrete (citing LRA Table 3.3-1, item 3.3.1-112 and plant-specific note 4) have no aging effect requiring management (AERM) and no recommended AMP. Plant-specific note 4 states:

> The Service Water system contains buried piping that is embedded in the reinforced concrete foundation of the Turbine Building Complex. The reinforced concrete foundation, which is founded on the underlying bedrock at the site, provides protection to the below-grade piping. This area, including any potential ground water exposure, is considered oxygen deficient and not conducive to active corrosion. Therefore, no aging affects are assumed for the carbon steel piping embedded in the reinforced concrete foundation of the Turbine Building Complex.

Issue:

It is not clear to the staff that all the buried in-scope piping components have been identified as being within the scope of the Buried and Underground Piping program. In addition, during the audit, the staff reviewed the foundation drawing and UFSAR Sections 2.4.12 and 2.4.13.3, which appear to show that the ground water table is very close to this piping. It is not clear to the staff that the ground water would be oxygen deficient and therefore, it may not be appropriate to state that no AERM and AMP are applicable.

The abstract for a study conducted by the Illinois State Water Survey, "Dissolved Oxygen and Oxidation-Reduction Potentials in Ground Water," April 1986, states that dissolved oxygen concentrations were near saturation 9 feet below the water table and nearly zero at 78 feet below the water table. The study cites the potential for some atmospheric oxygen contamination through the Teflon sampling tubing, but this does not invalidate the conclusion that oxygen can be present at higher elevations in the water table.

Request:

State the basis for why the area in the vicinity of the service water piping embedded in the reinforced concrete foundation of the turbine building should be considered oxygen deficient and why aging effects are not anticipated to occur. Alternatively, state what aging effect should be managed and which AMP is proposed.

Exelon Response:

With regard to Plant-Specific Note 4 for LRA Table 3.3.2-22, Service Water System, the area regarded as oxygen deficient is that which is in direct contact with the piping. Since the piping is embedded in the foundation of the building, the only potential for external loss of material to occur would be due to water seeping through the reinforced concrete foundation of the building. The permeability of the reinforced concrete could potentially allow small amounts of water to seep into the concrete foundation and contact the piping.

Although any water that might come into contact with the external surface of the piping embedded in the reinforced concrete foundation would result in oxidation, the free oxygen present would be consumed and the reaction terminated. In order for active corrosion to progress, a constant replenishing source of water would be required to deliver new sources of dissolved oxygen that could sustain the oxidizing reaction. Given this logic, it was not considered plausible that a sufficient quantity of oxygenated water could continuously reach the pipe surface and result in significant corrosion. Therefore, loss of material of the external surface of embedded Service Water piping was not considered an aging effect requiring management.

However, it is recognized that there is no means to visually verify these assumed conditions on the underside of the Turbine Building foundation. Therefore, LRA Table 3.3.2-22 is revised to manage the external surface of carbon steel Service Water piping embedded in the reinforced concrete foundation of the Turbine Building. The loss of material aging effect for the external surface of this piping will be managed by the Buried and Underground Piping (B.2.1.28) program. Original plant specifications do not require coatings to be installed for carbon steel piping embedded in reinforced concrete. This exception is further discussed under Exception 1 to the Buried and Underground Piping (B.2.1.28) program in the LRA. Exception 1 is currently identified as "Byron only." Given that carbon steel piping embedded in reinforced concrete at Braidwood Station is now managed by the Buried and Underground Piping (B.2.1.28) program, Exception 1 will be revised to eliminate the "Byron only" designation.

LRA Table 3.3.2-22 is revised as shown in Enclosure B of this letter. LRA Appendix B.2.1.28 is also revised as shown in Enclosure B of this letter.

As part of an extent of condition review, it was identified that portions of the Fire Protection and Main Condensate and Feedwater system piping are also embedded in the reinforced concrete foundation of the Turbine Building. The loss of material aging effect for this piping will also be managed by the Buried and Underground Piping (B.2.1.28) program. LRA Section 3.3.2.1.12, Section 3.4.2.1.3, Table 3.3.2-12, and Table 3.4.2-3 are revised to include the concrete environment for piping, as shown in Enclosure B of this letter.

<u>RAI B.2.1.28-2</u>, In-scope make-up water piping from the river screenhouse house buried in concrete (035)

<u>Applicability</u>: Byron

<u>Background</u>:

Exception No. 1 in the LRA Buried and Underground Piping Program states that original plant specifications did not require coatings to be installed for carbon steel piping embedded in reinforced concrete. The "preventive actions" and "detection of aging effects" program elements in LR-ISG-2011-03 recommend that coatings and cathodic protection be provided for steel piping and that inspection locations be based on risk (i.e., susceptibility to degradation and consequences of failure).

During the audit, the applicant stated that the in-scope make-up water piping from the river screenhouse is buried in concrete, not coated, and is provided with cathodic protection. The applicant also stated that it is not currently possible to verify the level of cathodic protection provided to this portion of the piping system.

<u>Issue</u>:

It is not clear to the staff how the risk level of this piping will be established for determining site inspection priorities given that the level of cathodic protection cannot be verified for the in-scope make-up water piping from the river screenhouse buried in reinforced concrete.

<u>Request</u>:

State how risk ranking factors will be determined for the in-scope make-up water piping from the river screenhouse buried in reinforced concrete.

<u>Exelon Response</u>:

The existing Byron and Braidwood buried pipe programs incorporate a risk ranking methodology for prioritizing indirect and direct inspections. The risk ranking process is applied to individual zones of piping, and is a factor of the susceptibility of the piping zone to degradation and the consequences of its failure. This risk ranking methodology is modified from the NACE Standard RP0502-2002 and is consistent with EPRI's "Recommendations for an Effective Program to Control the Degradation of Buried Pipe", as well as LR-ISG-2011-03 Element 4.b.iii.

As part of the determination of susceptibility factors in risk ranking buried pipe zones, various cathodic protection parameters are incorporated. Specifically, if cathodic protection is either not installed or not functional, the susceptibility ranking is increased. When cathodic protection is installed, cathodic protection system availability is a contributing input into the ranking of individual buried pipe zones as well. Coating-related parameters are also a part of the susceptibility determinations. Included in the evaluations are the presence or absence of coatings, overall age of the coating systems, and inputs based on direct observations of coating conditions once excavated.

The carbon steel Service Water make-up lines consist of field welded segments that are electrically continuous along their entire length. Cathodic protection surveys have shown these pipes to be cathodically protected inside the Byron Station protected area, south of the power block and west of the Essential Service Water Cooling Towers. However, until recently there have been no cathodic protection test locations along the Service Water make-up lines outside of the Byron Station protected area, down to the river screenhouse. Two carbon steel Circulating Water pipes also run immediately adjacent to the Service Water make-up lines from the river screenhouse to the main plant site. These two Circulating Water pipes are similarly cathodically protected inside the Byron Station protected area, however, multiple cathodic test locations are provided along the runs of Circulating Water pipe down to the river screenhouse. Annual cathodic protection surveys have shown these two Circulating Water pipes to be cathodically protected along that length. Based on this, the Service Water make-up lines are considered to be cathodically protected as well. However, due to the absence of direct observation of cathodic protection values for the Service Water make-up pipes, the buried pipe program has initially assigned a higher susceptibility value to these applicable buried Service Water make-up pipe zones. The assigned susceptibility value conservatively assumes that cathodic protection is either not present or not functional for these pipe zones. Therefore, the risk ranking of the applicable piping zones associated with the Service Water make-up piping from the river screenhouse, embedded in reinforced concrete, have currently addressed the unknown state of cathodic protection conditions described in the Staff's *Issue*.

Cathodic protection test locations are currently being installed to evaluate the degree of cathodic protection provided to each of the two Service Water make-up pipes embedded in reinforced concrete. The test locations are being installed on vacuum breaker riser pipes associated with each Service Water make-up pipe. The cathodic protection test locations will be at three separate positions along the length of the piping. These test locations will be incorporated into annual NACE cathodic protection surveys to assess the degree of cathodic protection being provided to each of the Service Water make-up pipes. The results of the annual surveys and assessment of the functionality and availability of cathodic protection for these zones can then be incorporated into the future susceptibility and overall risk ranking for the Service Water make-up pipes embedded in reinforced concrete.

<u>RAI B.2.1.28-3</u>, Cathodic protection millivolt polarization criteria (035)

<u>Applicability</u>: Byron and Braidwood

<u>Background</u>:

Enhancement No. 9 in the LRA Buried and Underground Piping Program states that a -850mV polarized potential criterion will be used during cathodic protection surveys unless the -100mV polarization criterion can be demonstrated to be effective through the use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.

<u>Issue</u>:

Based on the information provided in the LRA, the staff lacks sufficient information related to the how coupons, electric resistance probes, or reference cells will be used.

<u>Request</u>:

If the -100 mV polarization criterion will be used in a mixed metal environment, respond to the following:

a. State which industry consensus documents will be used to install and use the corrosion rate monitoring devices or reference electrodes.

b. State the acceptance criteria for general and pitting corrosion rates when using electrical resistance probes or coupons.

c. If coupons will be used, respond to questions i through iii.

   i. Describe the corrosion coupon characteristics, including:
      - the type of coupon to be used (e.g., free-corrosion coupon, polarized and native coupon pair, gravimetric, electrical resistance probe);
      - whether the coupons will be coated with an intentionally embedded holiday;
      - the surface condition (e.g., presence of scale and corrosion products, surface finish) of coupons; and
      - the composition of the coupon compared to the pipe (e.g., chemical composition and microstructure).

   ii. Describe the coupon placement, including:
      - how coupon locations will be selected so that they will be representative of the CP conditions at the point of interest;
      - the number of coupons that will be buried for each linear length of buried pipe;
      - coupon size and orientation with respect to the pipe, for example, how close both in distance and elevation the coupons will be installed to the pipe; and whether coupon will be perpendicular or parallel with the pipe;
      - the length of time coupons will be allowed to be buried;
      - how many years the coupons will be buried prior to accepting results;
      - for a given portion of pipe, how will the impact of localized soil parameters, such as soil resistivity, soil chemistry, moisture content, temperature and microbiological activity, be considered;
      - how voids in the backfill will be avoided when installing coupons; and
      - how seasonal variability will be accounted for on soil characteristics.

   iii. Describe the analysis of coupon results, including:

- what guidance will be used regarding coupon cleaning, corrosion rate calculations, and data reporting; and
- how pitting rates versus general corrosion rates will be differentiated.

Exelon Response:

a. Soil corrosion (electrical resistance) probes will be uncoated and placed in the immediate vicinity of the buried piping it is representing. For each installation application, two (2) probes will be installed; one connected to the cathodic protection system and one left unprotected. This will allow for comparison of the corrosion rates relative to cathodic protection effectiveness. Information provided in National Association of Corrosion Engineers (NACE) International Publication 05107, *"Report on Corrosion Probes in Soil or Concrete"* will be considered during the application, installation, and use of soil corrosion probes. This report is a document that has been prepared and approved by NACE International relative to the use of soil corrosion probes. However, the specific details on installation and use of the soil corrosion probes will be in accordance with vendor, manufacturer, and NACE qualified cathodic protection expert recommendations.

b. Soil corrosion (electrical resistance) probes are a commonly used means to verify cathodic protection (CP) effectiveness in mitigating corrosion, including areas where it has proven impractical to meet existing CP criteria. In these situations, the soil corrosion probes can be used to demonstrate an effective degree of cathodic protection even where the required polarization from industry standards, such as the -850mV "instant-off" polarization, cannot be achieved. The soil corrosion probes are capable of measuring corrosion rates of the probe at the locations of interest by correlating increases in electrical resistance to a loss of material of the probe. The probes measure cumulative loss of probe material and, when periodically surveyed, can be used to establish a corrosion rate. This corrosion rate is an indicator of how well the cathodic protection system is operating and protecting an uncoated metallic object in the area the probe is representing, such as a coating holiday. Although corrosion rates are determined, the purpose, for the intent of this aging management program, is not to demonstrate that the component intended function will be maintained based upon that rate and that no direct visual inspections are required. Rather, the observed corrosion rate will serve as a means to assess how effective the cathodic protection system is, for the given surveillance period, in mitigating corrosion at a simulated coating holiday. Under ideal conditions, a corrosion rate near zero will indicate that the electrical potential of the metal has been shifted from a relatively anodic state to cathodic state, such that significant corrosion is not occurring, thereby indicating an effective degree of cathodic protection. In the absence of adequate cathodic protection, corrosion can occur on uncoated pipe or areas of coating holidays and result in an observed corrosion rate at the soil corrosion probes that can be evaluated and the significance determined.

The effectiveness of a cathodic protection system in mitigating on-going corrosion is a principle attribute in determining the number of direct visual inspections needed to provide reasonable assurance of the condition of an SSC. For the purposes of Enhancement 9, evaluations of cathodic protection effectiveness will be based on either the -850mV "instant-off" criterion from NACE SP0169-2007, or observed corrosion rates at the time of surveillance taken from installed soil corrosion probes. When the -850mV "instant-off" NACE criterion is not met, the following steps may alternatively be used to assess cathodic protection effectiveness during the annual surveys, utilizing information from installed soil corrosion probes:

- If the measured corrosion rate from the soil corrosion probes indicates a material loss of one (1) mill per year (mpy) or less, cathodic protection will be considered effective for that given surveillance year and no further evaluation is necessary. The loss of material rate for the given surveillance year will be established based on the past one year of measurements taken on a monthly frequency, in conjunction with rectifier readings.

- If the measured corrosion rate for the given surveillance year exceeds the one (1) mpy criterion, the corrosion rate will be used as an input into a remaining life calculation for the pressure boundary function of the piping of interest. If the measured corrosion rate for the given surveillance year indicates that the remaining life of the pipe exceeds the life of the plant, such that the function of the SSC will be maintained during the period of extended operation, this would support the conclusion that the cathodic protection system has been performing as designed. As a result, cathodic protection will be considered effective in mitigating significant corrosion for that surveillance year at the location of interest.

  The remaining life calculation will be based on previous volumetric wall thickness measurements, annual corrosion rates and cumulative total loss of material since the volumetric measurements, and the current years' measured corrosion rate extrapolated through the end of the life of the plant.

- If the observed corrosion rates from the probes, over the given surveillance year, do not support the conclusion that intended function of the SSC would be maintained through the period of extended operation, this would indicate that the cathodic protection system has not been performing as designed and has not been effective over the surveillance interval. The measurements will count against the cathodic protection effectiveness determinations performed in accordance with LR-ISG-2011-03, Element 4, Table 4a, Footnote 2.c.iii to determine the number of direct visual inspections to perform during each ten year period, beginning ten years prior to the period of extended operation.

c. Buried coupons, which are not "soil corrosion probes", will not be used at Byron and Braidwood Stations to verify the effectiveness of the cathodic protection system or support use of the -100mV criteria. Therefore, this eliminates the need to answer parts 'i.' through 'iii.'. The mention of buried coupons and proximity placement of reference cells in Enhancement 9 will be removed from affected LRA sections. LRA Appendix A.2.1.28 and LRA Appendix B.2.1.28 are revised as shown in Enclosure B. LRA Table A.5 Item 28 is revised as shown in Enclosure C.

RAI B.2.1.28-4, Essential service water valve pits water intrusion (035)

Applicability: Byron

Background:

The "operating experience" program element in the LRA Buried and Underground Piping Program cites an example where at Byron inspection personnel discovered 8 – 10 feet of water in an essential service water valve pit. The in-scope piping was immersed in water. The water was removed, ultrasonic thickness measurements of the piping were performed, and the piping was recoated with a protective coal tar coating and polymeric tape wrap. The inspection frequency for both essential service water valve pits at Byron was changed from every two years to every three months.

Issue:

The staff reviewed the results of the preventive maintenance activities associated with the essential service water valve pits which experienced water intrusion from 2010 to the present. Of 21 inspections, 7 inspections observed 10 inches or less of water, 7 inspections provided no water quantity or level data, and 7 inspections observed 14 inches or more in the pit. The bottom of the essential service water pipe is at 18 inches. Based on a review of the inspection results, it is not clear that the inspection interval at Byron is sufficient to prevent the in-scope piping from being periodically rewetted. It is also not clear to the staff that the coating system is adequate for immersion, drying, and rewetting.

Request:

State the basis for why the inspection interval at Byron station provides reasonable assurance that the current licensing basis intended function of in-scope piping in the pits will be met during the PEO.

Exelon Response:

Byron Operating Experience example #1 included in the Buried and Underground Piping (B.2.1.28) program of the LRA refers to two essential service water valve pits. Since 2009, these essential service water valve pits have been opened and inspected for accumulated water on a quarterly basis. While the essential service water valve pits are opened and the piping made accessible, engineering has the opportunity to inspect the condition of the piping and components. Although water levels have, on a few occasions, resulted in exposure of the piping to standing water, the components have not been subjected to extended periods of contact with accumulated and standing water inside the vaults. Additionally, the piping and components contained within these valve pits were recoated in 2012.

In order to ensure that the intended function of the service water piping and components inside the essential service water valve pits are maintained during the period of extended operation, the maintenance activity will be enhanced to ensure direct visual inspections of the piping and components are performed by engineering. Visual inspections of the piping and components will verify the absence of any degradation to the protective coating and underlying metal. If evidence of degradation is identified, the condition will be entered into the corrective action program and corrective actions initiated to repair the piping, components, or protective coatings as appropriate.

As noted in the Staff's Issue above, and based upon a review of documented water levels from quarterly inspections, the number of instances the pipes in the essential service water valve pits have been in contact with water has been limited. Furthermore, considering the current surveillance frequency, the total amount of time the piping could be partially submerged between quarterly surveillances is short. Therefore, the requirement to visually inspect the underground service water piping in the essential service water valve pits on a quarterly basis will ensure the condition of the piping is adequately monitored and the current licensing basis intended function is maintained during the period of extended operation. The quarterly surveillance may be eliminated if either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications.

Based on the above, Enhancement 7 to the Buried and Underground Piping (B.2.1.28) program is revised to address the piping and components inside the essential service water valve pits. LRA Appendix A.2.1.28 and LRA Appendix B.2.1.28 are revised as shown in Enclosure B. LRA Table A.5 Item 28 is revised as shown in Enclosure C.

RAI B.2.1.28-5, buried and underground piping coatings disbondment, corrosion, and degradation (035)

Applicability: Byron and Braidwood

Background:

Based on a review of inspection reports and plant-specific operating experience, it appears that there have been several instances of inadequate initial preparation of coatings resulting in disbondment and minor corrosion. For example:

- NUC2011109.00 (Byron) stated that, "[w]ith regard to the as-found coating condition, localized coating damage appears to be largely the result of mechanical damage resulting from the original installation or excavation for inspection."
- In addition to the NUC report, the following Action Requests (AR) identified degraded coatings or loss of material for essential service water piping: AR 00689316, AR 00700422, and AR 00730278, and AR 00154572.
- NUC2010111.00 (Braidwood) stated that, "[i]n some locations, lack of overlap exposed the underlying coating or steel substrate. These exposed areas exhibited minor corrosion activity but no significant pitting."

Issue:

Based on this plant-specific operating experience, the staff lacks sufficient information to understand the extent of condition of coating degradation and quality of the original coating installation. In conjunction with this, the staff's review of cathodic protection survey reports for both Byron and Braidwood indicates that cathodic protection coverage has been improving, but the protection level is not consistently meeting the recommendations in LR-ISG-2011-03. As a result of these observations, the staff cannot conclude that the preventive actions and plant-specific conditions for buried piping are bounded by the conditions for which the GALL Report AMP was evaluated (e.g., quantity of inspections, frequency of inspections).

Request:

Given the plant-specific operating experience in relation to the quality of coatings, state the overall condition of coatings as a preventive action in relation to crediting them for the preventive action categories of LR-ISG-2011-03, Table 4a, "Inspections of Buried Pipe."

Exelon Response:

As noted in the *Background* section, a number of coating deficiencies have been documented in inspection reports and the Corrective Action Program at Byron and Braidwood Stations. Recently, Byron and Braidwood have experienced an adverse trend in the number of coating deficiencies identified during inspection of buried piping. Many of these coating deficiencies have been attributed to the excavation process or improper application of coatings during previous repair. Coating anomalies and deficiencies have been entered into the corrective action program which has resulted in extent of condition investigations and expansion of inspection scope. Based on corrective actions that have been implemented, the system leakage testing performed on the Fire Protection systems, as well as future actions outlined in Enhancement 6, the credited preventive measures associated with buried piping within the scope of license renewal are adequate to manage and mitigate the effects of aging during the period of extended operation.

Provided below is a discussion of the coating conditions discovered during inspections at Byron and Braidwood Stations, as well as corrective actions taken and planned.

Braidwood Station systems:

There are three (3) systems at Braidwood Station containing buried piping that is within the scope of license renewal. These three (3) systems are the Main Condensate and Feedwater System, Fire Protection System, and Service Water System. Each of these is discussed as follows:

Main Condensate and Feedwater System

The buried in-scope piping included within the license renewal Main Condensate and Feedwater System includes carbon steel portions of the station's nonsafety-related condensate system. The referenced statement in the above cited bullet for Braidwood, specifically *NUC2010111.00*, was in relation to a not-in-scope Circulating Water System pipe inspection. Nonetheless, other coating deficiencies for in-scope condensate system piping have been documented. Enhancement 6 to the Buried and Underground Piping (B.2.1.28) aging management program was developed to address the deficiencies in the preventive measures associated with the buried condensate system piping. Therefore, upon implementation of Enhancement 6, the preventive measures in place for the buried condensate system will provide adequate protection of the in-scope piping. As a result, inspection quantities performed in accordance with LR-ISG-2011-03 Table 4a will provide reasonable assurance of the condition of buried in-scope condensate system piping, and ensure that it will continue to perform its intended function through the period of extended operation.

Fire Protection System

The Fire Protection System at Braidwood Station is coated and provided with cathodic protection. Recently, a number of coating flaws have been observed on excavated Fire Protection System piping. At the location of the coating flaws, highly localized corrosion has been observed due to inadequate cathodic protection. In some cases, the localized corrosion resulted in through-wall leakage. However, the areas surrounding the localized coating failures have been well protected and appeared in excellent condition with little to no surface corrosion. The cause of the coating failures has been attributed to improper application of field applied coatings and damage to the manufacturer applied coating. These events and conditions have been entered into the corrective action program, and as a result, a long term strategy to address Fire Protection System piping is being developed. Additionally, improvements to the cathodic protection system are planned and being investigated in order to better protect buried piping at Braidwood Station. Furthermore, although leaks have occurred on buried portions of the Fire Protection System ring header, multiple measures are in place to detect and manage system leakage.

In order to detect and manage system leakage, two (2) jockey pumps will provide a total of up to 200 gallons per minute (gpm) make-up to maintain the system pressurized before automatic start of the fire pumps, and until such time that the leak be identified and isolated.

The outdoor direct buried ring header can be isolated into four (4) sections by post-indicator valves in the yard. There are also five (5) connections between the outdoor buried ring header and the interior headers inside the Auxiliary Building, Fuel Handling Building, and Turbine Building. The jockey pumps make-up capability, the ability to isolate leaking portions of the outdoor buried ring header, and the multiple connections to safety-related structures will ensure sufficient water is provided to the safety-related structures to fight potential fires.

As documented in Exception 4 to the Buried and Underground Piping (B.2.1.28) aging management program, the buried portions of the Fire Protection System will be managed through annual system leakage testing, also referred to as pressure decay tests. During this test, the Fire Protection System header pressure is elevated by initially running one of the two (2) jockey pumps. The elevated pressure is documented, jockey pump operation is terminated, and the rate of system pressure decrease is determined and compared to established acceptance criteria. Any abnormal pressure decay rates will result in investigation of the cause in accordance with station procedures. Furthermore, each of the two (2) jockey pumps is functionally tested on a quarterly basis. Any significant system leakage would result in excessive running of the jockey pumps and would be detected and investigated by operations personnel performing the testing. Operator walkdowns are also performed daily of plant equipment, where excessive running of the jockey pumps has previously been identified, entered in the corrective action program, and the cause investigated and corrected. Also, control room indication of jockey pump operation is also provided and continuous or excessive jockey pump operation has been previously identified, entered in the corrective action program, and the cause investigated and corrected. The buried outdoor ring header is also located at a relatively shallow depth below grade, approximately six (6) to ten (10) feet, such that indications of previous system leaks have manifested at the surface and have been easily identified by station personnel during walkdowns.

The XI.M41 buried and underground piping aging management program, as specified in Revision 2 of NUREG-1801 and in LR-ISG-2011-03, allows for alternatives to performing direct visual inspections of the external surface of buried portions of fire protection systems. These alternatives include measures such as annual flow testing, in accordance with Section 7.3 of NFPA 25, and periodic monitoring of jockey pump activity. Both of the alternatives are methods capable of detecting varying degrees of leakage occurring within the Fire Protection System. Furthermore, NUREG-1950 includes the following technical basis to support the use of these alternatives:

> It should be noted that [NFPA 24] permits some leakage from brand new fire mains. While flow testing will not detect small leaks, it will ensure that the intended function of fire mains, delivering sufficient water to fight fires, is maintained. It is also noted that leakage from fire mains presents no environmental hazard.
>
> The frequency at which the flow tests are performed [one year] is sufficient to ensure that adequate water flow is maintained even if a leak were to develop between two tests. Additionally, pressure is maintained in the fire main systems through the use of jockey pump.

Based upon the above information, the measures in place at Braidwood Station to manage the Fire Protection System are consistent with the NUREG-1801 and LR-ISG-2011-03

XI.M41 buried and underground piping aging management program, as well as the technical bases outlined in NUREG-1950. Although Braidwood has experienced buried pipe leaks and identified coating flaws in the Fire Protection System, these conditions are bounded by the assumptions inherent to the use of the alternative measures for managing fire protection piping, as contained in the aforementioned documents. Additionally, due to a number of buried Fire Protection System leaks that have occurred, approximately 270 feet of carbon steel piping was replaced in 2013 with HDPE piping in an area that had experienced recent leakage. These events have been entered into the corrective action program and as a result, a long term strategy to address the remainder of the buried Fire Protection System ring header is currently being developed. Improvements to the cathodic protection system throughout the site are also planned in order to better protect buried piping. Therefore, there is reasonable assurance that the Fire Protection System will be adequately managed during the period of extended operation.

Service Water System

Buried pipe coating deficiencies identified in other Braidwood systems have all occurred at locations of compacted backfill. The entire length of the carbon steel Service Water System, that is within the scope of license renewal, is backfilled in a cementitious low strength material (CLSM). Backfilling of the Service Water pipes in CLSM limits the possibility of coating damage during the backfill process, as well as provides an additional barrier of protection to potentially damaged areas and protection against age-related degradation of the intact coating itself. Therefore, the preventive measures in place for the buried Service Water piping will provide adequate protection of the in-scope piping. As a result, inspection quantities performed in accordance with LR-ISG-2011-03 will provide reasonable assurance of the condition of the buried in-scope Service Water System piping to ensure that it will continue to perform its intended function through the period of extended operation.

Braidwood Station systems summary:

Excavations at Braidwood Station have identified a number of coating deficiencies that are associated with piping that is within the scope of license renewal. In the case of the plant condensate system, significant extent of condition excavations and recoating of excavated piping have already occurred, and as documented in Enhancement 6 to the Buried and Underground Piping (B.2.1.28) aging management program, the remainder of the condensate system will be addressed through a long term mitigation strategy. With respect the Fire Protection System, multiple measures are in place to both detect and manage system leakage while still ensuring that the system function, to deliver sufficient water to fight fires, is maintained. The Service Water System is backfilled in CLSM along its entire length and is considered adequately protected. Therefore, the preventive measures and actions in place for buried in-scope piping at Braidwood Station are sufficient to support performance of inspection quantities in accordance with LR-ISG-2011-03, Table 4a and provide reasonable assurance that the intended function of in-scope SSCs will be maintained during the period of extended operation.

<u>Byron Station systems:</u>

There are four (4) systems at Byron Station containing buried piping that is within the scope of license renewal. These four systems are the Main Condensate and Feedwater System, Fire Protection System, Service Water System, and Demineralized Water System. Each of these is discussed as follows:

Main Condensate and Feedwater System

The buried in-scope piping included within the license renewal Main Condensate and Feedwater System includes carbon steel portions of the plants nonsafety-related condensate system. Condensate system piping is nonsafety-related, does not contain hazardous material such as tritium and oil, and is therefore, risk ranked low within the existing buried pipe program. As a result, no direct visual inspections of buried condensate system piping have occurred. There have been no externally initiated leaks on the buried portions of the condensate system, indicating that the undisturbed coating is providing adequate protection and/or the cathodic protection system has been effective in mitigating any significant corrosion. The length of the in-scope buried condensate system piping will be included as part of the population to be considered for extent of condition evaluations if coating deficiencies are found elsewhere on in-scope buried carbon steel piping backfilled in compacted fill. Therefore, performance of inspection quantities in accordance with LR-ISG-2011-3, Table 4a, will provide reasonable assurance that the intended function of in-scope SSCs will be maintained during the period of extended operation.

Fire Protection System

The Fire Protection System at Byron Station is coated and provided with cathodic protection. Although no leaks have occurred on buried portions of the Fire Protection System ring header at Byron Station, the measures that are in place to detect and manage system leakage are the same as those in place as Braidwood Station, described previously.

As documented in Exception 4 to the Buried and Underground Piping (B.2.1.28) aging management program, the buried portions of the Fire Protection System will be managed by performing annual system leakage testing, also referred to as pressure decay tests. This method and frequency is consistent with the intent of crediting flow tests, as allowed for in NUREG-1801, Chapter XI.M41 and LR-ISG-2011-03 XI.M41. Therefore, there is reasonable assurance that the Fire Protection System will be adequately managed during the period of extended operation.

Service Water

Approximately 95% of the buried carbon steel Service Water System piping within the scope of license renewal is backfilled in either a cementitious controlled low strength material (CLSM), or encased in reinforced concrete. The remaining 5% is backfilled in controlled compacted fill. Since 2009, 13 buried pipe inspections have occurred on buried Service Water piping backfilled in controlled compacted fill. The excavations and inspections have resulted in the observation of a number of noted coating deficiencies that exposed the underlying metal. Based upon a review of inspection reports documenting the conditions found, 12 of the 13 instances are considered to be due to either the excavation process, or were in areas of previous excavations and coating repair.

The 13th excavation, associated with a Service Water return bypass line to the cooling tower, exhibited minor coating damage and was considered to be due to reasons other than excavation or improper coating repair. No previous excavations and coating repair activities are known to have occurred in this area. The damaged area was found on a portion of the approximately eight (8) foot long excavated section and determined not to be due to the excavation process, as the underlying base material exhibited some indications of minor localized corrosion. Therefore, this condition is conservatively considered to have been an age-related failure. Ultrasonic thickness readings were taken, with the lowest area having a wall thickness greater than 64% of the nominal thickness. Although cathodic protection had been effective in mitigating significant corrosion, based on the general wall thickness readings taken along the entire excavated region, an additional cathodic protection test point was added to allow for more accurate trending in future surveys. Additionally, a permanent guided wave collar was also installed prior to recoating and burial to allow for additional wall thickness monitoring, particularly in the event of ineffective cathodic protection.

As a result of the one (1) age-related coating deficiency, as well as the areas of improper coating repair from excavations prior to 2009, an extensive extent of condition investigation is being implemented as part of a long term asset management strategy. This long term asset management strategy and extent of condition plan includes the excavation and recoating of the 24-inch Service Water return riser pipes, the 24-inch return bypass lines, and areas that were previously excavated prior to 2009. In addition, at least 10 new cathodic protection test points with new reference cells immediately adjacent to the Service Water piping have been installed in order to provide additional information on the degree of cathodic protection and at more locations across the in-scope piping. At least six (6) permanent guided wave collars have also been installed on buried Service Water piping during previous excavations. Four (4) guided wave collars have also been installed on Service Water piping inside of vaults and are capable of assessing additional lengths of the buried portions of the system. These will allow for periodic monitoring and trending for potential loss of material and indications of coating holidays in the upstream and downstream areas that have not yet been excavated and recoated.

Identified coating deficiencies discovered during excavations since 2009 have primarily not been age-related, but rather attributed to the excavation process, as well as improper application or damage during historical plant modifications and previous excavations. One eight (8) foot excavation was performed, however, with a portion of the coating system exhibiting age-related degradation. Based upon the approximately 300 feet of piping that has been inspected since 2009, this one identified area exhibiting age-related degradation is not considered representative and indicative of the condition of the entire 2000 foot population under consideration. However, as a result of this finding, as well as the areas of improper coating repair, implementation of an aggressive extent of condition investigation has begun on similar areas of interest. This extent of condition investigation is being tracked as part of a long term asset management plan, consistent with the attributes and milestones of the NEI 09-14, "Guideline for the Management of Underground Piping and Tank Integrity", Revision 3, initiative. The areas of similar interest are scheduled to be addressed, through excavation and recoating, over the next few years. Guided wave collars are also in place to monitor for loss of material due to potential coating holidays. During the course of this extent of condition investigation, Enhancement 8 to the Buried and Underground Piping (B.2.1.28) aging management program will sufficiently address the potential issue of further unanticipated coating deficiencies found during inspections performed during each of the three ten year periods, beginning ten years prior to the period of extended operation. This expansion of scope criteria will ensure that any conditions identified, including other in-scope systems of similar materials and backfill environments, will result in evaluation and scheduling of additional inspections consistent with Element 4.f.iii of LR-ISG-2011-03. Therefore, inspection quantities performed in accordance with LR-ISG-2011-03 Table 4a, in addition to Enhancement 8, will provide reasonable assurance of the condition of buried in-scope carbon steel Service Water System piping, such that the piping will continue to perform its intended function through the period of extended operation.

Demineralized Water System

The buried in-scope piping included within the license renewal Demineralized Water System includes portions of the plant's nonsafety-related well water system which provides make-up water to the Essential Service Water Cooling Towers. Only one (1) direct visual inspection of buried well water system piping has been performed. This inspection occurred on well water system make-up to the Essential Service Water Cooling Tower, approximately 30 feet from the cooling tower. Upon excavation, a minor coating anomaly was discovered to have existed based on the observation of five (5) small localized corrosion areas on the underlying metal which had formed on a 90 degree elbow. Ultrasonic measurements were taken showing all readings, except in the areas of the localized corrosion spots, to be above 89% nominal wall thickness. The pipe wall thickness of the five (5) areas of interest found on the piping elbow ranged from 60-85% nominal wall thickness. Prior to recoating and burial, a cathodic protection test point was installed to allow for more accurate cathodic protection readings and supplementary coverage. Additionally, a permanent guided wave collar was installed to allow for periodic future monitoring of pipe wall thicknesses.

As recognized by the Staff in the *Issue* section of this RAI, and supported by installation of numerous additional cathodic protection test points on excavated piping mentioned previously, the degree of understanding of cathodic protection coverage is being significantly improved at Byron Station, along with the overall health of the cathodic protection system. These types of improvements to the cathodic protection system will help mitigate similar types of degradation in the future.

This identified coating deficiency is also not considered representative of the overall buried in-scope portions of the Demineralized Water System. The amount of degradation of the underlying pipe was very limited, with only five localized areas exhibiting loss of material that resulted in the remaining pipe wall thickness falling below 87.5% of the nominal thickness, and all occurred at a 90 degree elbow which is considered to have greater susceptibility to coating damage. There is approximately 2,600 feet of in-scope buried carbon steel Demineralized Water System piping backfilled in compacted fill, including approximately 20 piping elbows or tees. Straight portions of the excavated piping exhibited adequate corrosion protection and lack of overall general corrosion of the underlying material, representative of the vast majority of the remainder of the in-scope system. Piping elbows receive a higher susceptibility and overall risk ranking within the buried piping program database as well, and are prioritized for inspection accordingly. As such, discovery of potential flaws are more highly anticipated at these locations.

Based on the above, Enhancement 8 to the Buried and Underground Piping (B.2.1.28) aging management program for expansion of inspection scope will sufficiently address the potential issue of further unanticipated coating deficiencies found during the course of inspections performed during each of the three ten year periods, beginning ten years prior to the period of extended operation. This expansion of scope criteria will ensure that any conditions identified, including other in-scope systems of similar materials and backfill environments, will result in evaluation and scheduling of additional inspections consistent with Element 4.f.iii of LR-ISG-2011-03. Therefore, inspection quantities performed in accordance with LR-ISG-2011-03 Table 4a, in addition to Enhancement 8, will provide reasonable assurance of the condition of buried in-scope Demineralized Water System piping, and ensure that it will continue to perform its intended function through the period of extended operation.

Byron Station systems summary:

Excavations at Byron Station have identified a number of coating deficiencies that are associated with piping that is within the scope of license renewal. Based on a review of the identified deficiencies, the cause has primarily been due to the excavation process, or related to improper application during coating repairs prior to 2009. As a result, however, there has been a number of extent of condition excavations performed and recoating of excavated piping. Implementation of a long term asset management plan has also begun to continue addressing potential coating deficiencies, particularly in the areas of previous coating repairs and high risk areas associated with pipe configuration geometries. Due in part to the overall health of the cathodic protection system and limited extent of age-related coating degradations found in excavations performed to date, Byron has not experienced a buried piping leak as a result of external corrosion on any of the in-scope piping. Furthermore, given the industry operating experience factors now known relative to the importance of proper coating applications, there is increased sensitivity toward ensuring proper craftsmanship in the application of coatings, as well as in the care taken during backfill operations. Therefore, the preventive measures and actions for buried in-scope piping at Byron are sufficient to support performance of inspection quantities in accordance with LR-ISG-2011-03, Table 4a and provide reasonable assurance that the intended function of in-scope SSCs will be maintained during the period of extended operation.

RAI B.2.1.23-1, Cracking of stainless steel components exposed to air environments containing halides (037)

Applicability: Byron and Braidwood

Background:

Cracking of stainless steel components exposed to air environments containing halides may be managed by GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components."

SRP-LR Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2 state that the GALL Report recommends further evaluation to manage cracking due to SCC of stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air environments containing sufficient halides (primarily chlorides) and in which condensation (including rain) or deliquescence is possible. These SPR-LR Sections further state that applicable outdoor air environments include those plants within a half a mile of a highway which is treated with salt in the wintertime and those having cooling towers where the water is treated with chlorine or chlorine compounds.

LRA Section 3.2.2.2.6 states, "[a] large buildup of halide contamination increases the probability of cracking due to stress corrosion cracking which has the potential to lead to loss of component intended function." LRA Section 3.2.2.2.6 also states that SCC of stainless steels exposed to outdoor air is considered plausible only if the material temperature is above 104°F. The LRA states that the highest recorded temperature since construction for the areas surrounding Byron and Braidwood indicates that the temperature rarely exceeds 100ºF, therefore SSC of stainless piping, piping components, piping elements exposed to outdoor air is not expected to occur at Byron and Braidwood.

The LRA states that the cooling towers at Byron are treated with sodium hypochlorite. The LRA further states that chloride contamination of stainless steel components located outdoors is not expected, since the prevailing wind direction is west to east and is directed away from the site. At Braidwood, an apparent cause evaluation of leaks in buried fire protection piping noted that for a segment of stainless steel piping, LS-AA-125-1003, stated, "[w]here the coating was disbonded, severe external pitting was identified, which included the location of the leak." This indicates the potential for chloride or halides to be present in the soil and atmosphere at Braidwood.

The LRA Tables list many aluminum and stainless steel components exposed to outdoor air. Note that the aluminum condensate storage tanks will be addressed for SCC due to exposure to outdoor air by a separate RAI (B.2.1.17-1).

Issue:

LRA table 3.0-1 describes air – outdoor as an environment that is periodically subject to wetting and wind. The staff believes rain could introduce halides, which are known to contribute to SCC, to the surface of stainless steel components. Additionally aluminum components are subject to SCC due to exposure to halides.

Given that a prevailing wind direction at Byron is expected to be directed away from the site, does not result in the absence of contaminant deposition by the cooling tower plume. In addition, the presence of contaminates in the soil at Braidwood which resulted in pitting of stainless steel buried piping lends credence to the position that halides could be present in the atmosphere at Braidwood. The staff lacks sufficient information to conclude that SCC cannot occur in stainless steel and aluminum components located in an outdoor air environment.

Request:

1. Provide the basis for why the chemical compounds in the cooling tower plume at Byron cannot result in SCC if plume fallout (regardless of prevailing wind direction) accumulates on the external surfaces of aluminum and stainless steel components exposed to outdoor air within the scope of license renewal.

2. Provide the basis for why the soil contamination found at Braidwood could not result in SCC of aluminum and stainless steel components exposed to outdoor air within the scope of license renewal.
3. If cracking is an applicable aging effect, state what inspection methods will be used to detect cracking and the acceptance criteria for cracks.

Exelon Response:

1. As described in LRA Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2, cracking due to stress corrosion cracking (SCC) is not expected to occur for stainless steel components exposed to outdoor air at Byron and Braidwood. However, since it has not been demonstrated that the environmental halide levels at Byron preclude the occurrence of SCC, updates to appropriate LRA sections are being made, as described in response item 3 below, to reflect the possibility of SCC of un-insulated in-scope aluminum and stainless steel components at Byron.

2. As described in LRA Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2, cracking due to stress corrosion cracking (SCC) is not expected to occur for stainless steel components exposed to outdoor air at Byron and Braidwood. However, since it has not been demonstrated that the environmental halide levels at Braidwood preclude the occurrence of SCC, updates to appropriate LRA sections are being made, as described in response item 3 below, to reflect the possibility of SCC of un-insulated in-scope aluminum and stainless steel components at Braidwood.

3. As a result of the conclusions discussed above in response items 1 and 2, aluminum and stainless steel piping, piping components, and piping elements and tanks exposed to outdoor air within the scope of license renewal have been re-evaluated for the potential aging effect of cracking. The review determined that no aluminum components are impacted from these findings as they are either insulated or sheltered; or tanks (i.e. CSTs) that are discussed in RAI B.2.1.17-1.

   Liquid-filled (i.e., lubricating oil or treated water) in-scope stainless steel piping, piping components, and piping elements exposed to outdoor air include components associated with the instrumentation supporting the condensate storage tank heaters and the essential service water cooling tower gear reducer at Byron only. Although not expected to occur, cracking due to stress corrosion cracking will be added as an applicable aging effect / mechanism for these components. The LRA line items for these components are revised as shown in Enclosure B to specify the use of the External Surfaces Monitoring of Mechanical Components aging management program (B.2.1.23) to monitor for cracking of these components. The External Surfaces Monitoring of Mechanical Components aging management program (B.2.1.23) utilizes visual inspections for leakage for detection and identification of cracks.

Other liquid-filled in-scope stainless steel piping, piping components, and piping elements exposed to outdoor air are shielded from accumulation of potential contaminants in the environment either by jacketed insulation or by being located in an enclosed pit. As discussed in parts 1 and 2 of this response, cracking due to SCC is not expected to occur, but is possible, due to contamination of stainless steel and aluminum surfaces from environmental sources of halides. Should SCC occur due to halide contamination from environmental sources it is more likely that it would occur on surfaces that are directly exposed to the environment rather than surfaces that are protected or sheltered. SCC due to halide contamination from environmental sources is not credible for components that are shielded from accumulation of potential contaminants in the environment either by jacketed insulation or by being located in an enclosed pit.

Additionally, gas-filled, in-scope stainless steel piping, piping components, and piping elements exposed to outdoor air include components in the exhaust piping of the following three components: the emergency diesel generator, the diesel-driven fire pump, and the diesel-driven essential service water makeup pump. If cracking were to occur in the above diesel exhaust components the intended function of these components would not be affected since an exhaust path for the diesels would still be provided. Nevertheless, to confirm that cracking does not occur, the One-Time Inspection aging management program (B.2.1.20) will be used to assess the stainless steel components with direct exposure to outdoor air conditions. This only includes the essential service water makeup pump diesel exhaust lines (Byron Only) as the other two diesel systems stainless steel exhaust lines, described above, are insulated or otherwise sheltered from outdoor conditions, and therefore SCC due to halide contamination from environmental sources is not credible. The LRA line item for this component is revised as shown in Enclosure B to specify the use of the One-Time Inspection aging management program (B.2.1.20) to monitor for cracking of this component.

With the exception of the condensate storage tanks, there are no in-scope, metallic tanks exposed to the outdoor air environment. The aging effects associated with the condensate storage tanks are managed by the Aboveground Metallic Tanks aging management program (B.2.1.17).

As a result of RAI B.2.1.23-1, LRA Sections 3.2.2.2.6, 3.3.2.2.3, 3.4.2.2.2, Table 3.2-1, Table 3.3-1, Table 3.4-1, Table 3.3.2-22, Table 3.4.2-3, and Sections A.2.1.20, A.2.1.23, B.2.1.20, B.2.1.23 are revised to reflect the changes as shown in Enclosure B. The Byron and Braidwood LRA Table A.5 Commitment List, Items 20 and 23, are also revised as shown in Enclosure C.

<u>RAI B.2.1.25-1</u>, Representative sample sizes for Internal Surfaces in Miscellaneous Piping and Ducting Components program (039)

<u>Applicability</u>: Byron and Braidwood

<u>Background:</u>
The Internal Surfaces in Miscellaneous Piping and Ducting Components program does not have a representative minimum sample size for each material, environment, and aging effect combination crediting this program.

Recent industry OE and questions raised during the staff's review of several LRAs has resulted in the staff concluding that there should be a representative minimum sample size for periodic inspections for the GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components."

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

<u>Request:</u>

State how LRA Sections A.2.1.25 and B.2.1.25 will be revised to ensure that the Internal Surfaces in Miscellaneous Piping and Ducting Components Program conducts periodic inspections on a representative sample of in-scope components. Alternatively, state why no changes to the program are necessary to ensure that the aging effect(s) for each applicable material and environment combination will be appropriately managed during the PEO.

Exelon Response:

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program was reviewed, and it was determined that the program will be revised to ensure that the program conducts inspections on a representative sample of all material, environment, and aging effect combinations of in-scope components.

Therefore, LRA Sections A.2.1.25 and B.2.1.25 are revised using the guidance provided in License Renewal Interim Staff Guidance, LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation," to ensure that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program conducts inspections on a representative sample of in-scope components by performing periodic inspections, as required, to supplement opportunistic inspections. These LRA Sections are revised to require that at a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling requirement.

LRA Sections A.2.1.25 and B.2.1.25 are revised to reflect the changes discussed above, and are included in Enclosure B. LRA Table A.5, License Renewal Commitment List, Item 25, is revised to reflect the changes discussed above, and is included in Enclosure C.

Enclosure B

Byron and Braidwood Stations, Units 1 and 2
License Renewal Application (LRA) updates resulting from the responses to RAIs contained in Enclosure A of this letter

Note: The RAI numbers, affected LRA Sections and Enclosure pages for the associated LRA Section markups are identified below. To facilitate understanding, portions of the original LRA have been repeated in this Enclosure, with revisions indicated. Existing LRA text is shown in normal font. Changes are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the responses to RAIs 3.0.3-2 and 3.0.3-3 provided in Enclosure A of this letter, LRA Table 2.3.2-4, page 2.3-59, Table 2.3.3-1, page 2.3-75, Table 2.3.3-2, page 2.3-88, Table 2.3.3-3, page 2.3-98, Table 2.3.3-12, page 2.3-156, Table 2.3.3-22, page 2.3-232, Table 2.3.4-1, page 2.3-247, and Table 2.3.4-3, page 2.3-258, are revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 2.3.2-4 Safety Injection System
Components Subject to Aging Management Review

Component Type	Intended Function
Insulated piping, piping components, and piping elements	***Pressure Boundary***

Table 2.3.3-1 Auxiliary Building Ventilation System
Components Subject to Aging Management Review

Component Type	Intended Function
Insulated ~~P~~***p***iping, piping components, and piping elements	Structural Support

Table 2.3.3-2 Chemical & Volume Control System
Components Subject to Aging Management Review

Component Type	Intended Function
Insulated piping, piping components, and piping elements	***Leakage Boundary***
Insulated Pump Casing (BTR Chiller)	Leakage Boundary
Insulated Tanks (Chiller Surge)	Leakage Boundary
Insulated Valve Body	***Leakage Boundary***

Table 2.3.3-3 Chilled Water System
Components Subject to Aging Management Review

Component Type	Intended Function
Insulated piping, piping components, and piping elements	***Leakage Boundary***
	Pressure Boundary
Insulated Pump Casing (Auxiliary Building Chilled Water Pump)	Leakage Boundary
Insulated Pump Casing (Control Room Chilled Water Pump)	Pressure Boundary

Component Type	Intended Function
Insulated Pump Casing (Primary Containment Chilled Water Pump)	Leakage Boundary
Insulated Tanks - (Air Separator - Control Room)	Pressure Boundary
Insulated Tanks - (Air Separator With Strainer - Containment and Auxiliary Building)	Leakage Boundary
Insulated Tanks - (Chilled Water Tank - Containment and Auxiliary Building)	Leakage Boundary
Insulated Tanks - (Control Room Chilled Water System Standpipe)	Pressure Boundary
Insulated Valve Body	***Leakage Boundary***
	Pressure Boundary

Table 2.3.3-12 <u>Fire Protection System</u>
Components Subject to Aging Management Review

Component Type	Intended Function
Insulated piping, piping components, and piping elements	***Pressure Boundary***

Table 2.3.3-22 <u>Service Water System</u>
Components Subject to Aging Management Review

Component Type	Intended Function
Heat Exchanger - (Computer Room AC Condenser Coil ***– Braidwood only***) Tube Side Components	Leakage Boundary
Heat Exchanger - (Computer Room AC Condenser Coil – Byron only) Tube Side Components	***Leakage Boundary***
Heat Exchanger - (RCFC Essential Service Water Coils ***– Braidwood only***) Tube Sheet	Pressure Boundary
Heat Exchanger - (RCFC Essential Service Water Coils – Byron only) Tube Sheet	***Pressure Boundary***
Heat Exchanger - (RCFC Essential Service Water Coils ***– Braidwood only***) Tube Side Components	Pressure Boundary
Heat Exchanger - (RCFC Essential Service Water Coils – Byron only) Tube Side Components	***Pressure Boundary***

Component Type	Intended Function
Heat Exchanger - ([CV, SI, RH, CS, SX] Pump Cubicle Cooler ***– Braidwood only***) Tube Sheet	Pressure Boundary
Heat Exchanger - ([***1A, 1B, and 2A*** CV, ***1A and 2B*** SI, RH, ***1A, 1B, and 2A*** CS, SX] Pump Cubicle Cooler ***– Byron only***) Tube Sheet	Pressure Boundary
Heat Exchanger - ([2B CV, 1B and 2A SI, RH, 2B CS, SX] Pump Cubicle Cooler – Byron only) Tube Sheet	***Pressure Boundary***
Heat Exchanger - ([CV, SI, RH, CS, SX] Pump Cubicle Cooler ***– Braidwood only***) Tube Side Components	Pressure Boundary
Heat Exchanger - ([1A, 1B, and 2A CV, 1A and 2B SI, RH, 1A, 1B, and 2A CS, SX] Pump Cubicle Cooler – Byron only) Tube Side Components	***Pressure Boundary***
Heat Exchanger - ([2B CV, 1B and 2A SI, RH, 2B CS, SX] Pump Cubicle Cooler – Byron only) Tube Side Components	***Pressure Boundary***
Insulated piping, piping components, and piping elements	***Leakage Boundary***
	Pressure Boundary
Insulated Strainer Body	Leakage Boundary
	Pressure Boundary
Insulated Valve Body	***Leakage Boundary***
	Pressure Boundary

Table 2.3.4-1 **Auxiliary Feedwater System**
Components Subject to Aging Management Review

Component Type	Intended Function
Heat Exchanger - (AFW Cubicle Coolers ***– Braidwood only***) Tube Sheet	Pressure Boundary
Heat Exchanger - (1A and 2A AFW Cubicle Coolers – Byron only) Tube Sheet	***Pressure Boundary***
Heat Exchanger - (1B and 2B AFW Cubicle Coolers – Byron only) Tube Sheet	***Pressure Boundary***
Heat Exchanger - (AFW Cubicle Coolers ***– Braidwood only***) Tube Side Components	Pressure Boundary
Heat Exchanger - (1A and 2A AFW Cubicle Coolers – Byron only) Tube Side Components	***Pressure Boundary***

Component Type	Intended Function
Heat Exchanger - (1B and 2B AFW Cubicle Coolers – Byron only) Tube Side Components	***Pressure Boundary***
Insulated piping, piping components, and piping elements	***Pressure Boundary***
Insulated Valve Body	***Pressure Boundary***

Table 2.3.4-3 Main Condensate and Feedwater System
Components Subject to Aging Management Review

Component Type	Intended Function
Insulated piping, piping components, and piping elements	***Pressure Boundary***
Insulated Valve Body	***Pressure Boundary***

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Section 3.2.2.1.4, Safety Injection System, pages 3.2-4 and 3.2-5, is revised as shown below. Additions are indicated with ***bolded italics***.

3.2.2.1.4 Safety Injection System

Materials

The materials of construction for the Safety Injection System components are:

- Carbon Steel
- ***Carbon Steel (with internal lining or coating)***
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Copper Alloy with less than 15% Zinc
- Glass
- Gray Cast Iron
- Nickel Alloy
- Stainless Steel
- Stainless Steel Bolting

Aging Effect Requiring Management

The following aging effects associated with the Safety Injection System components require management:

- Cracking
- Cumulative Fatigue Damage
- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

As a result of the response to RAI B.2.1.23-1 provided in Enclosure A of this letter, LRA Section 3.2.2.2.6, pages 3.2-8 through 3.2-10, is revised as shown below. Additions are indicated with ***bolded italics***.

3.2.2.2.6 Cracking due to Stress Corrosion Cracking

Cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, piping elements and tanks exposed to outdoor air. The possibility of cracking also extends to components exposed to air which has recently been introduced into buildings, i.e., components near intake vents. Cracking is only known to occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. Condensation or deliquescence should generally be assumed to be possible. Applicable outdoor air environments (and associated indoor air environments) include, but are not limited to, those within approximately 5 miles of a saltwater coastline, those within 1/2 mile of a highway which is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources. This item is applicable for the environments described above.

GALL AMP XI.M36, "External Surfaces Monitoring" is an acceptable method to manage the aging effect. The applicant may demonstrate that this item is not applicable by describing the outdoor air environment present at the plant and demonstrating that external chloride stress corrosion cracking is not expected. The GALL Report recommends further evaluation to determine whether an aging management program is needed to manage this aging effect based on the environmental conditions applicable to the plant and requirements applicable to the components.

The only stainless steel components exposed to outdoor air in the Engineered Safety Features Systems are insulated portions of the piping vent line for the refueling water storage tank in the Safety Injection System. There are no stainless steels tanks exposed to an outdoor air environment in the scope of license renewal at Byron and Braidwood Stations (BBS). Stress corrosion cracking of these components is not expected to occur, however, should cracking occur the function of these components would not be affected since an exhaust path for the refueling water storage tank would still be provided.

The thermal insulation utilized for the refueling water storage tank vent line piping acts as a barrier to prevent the accumulation of halide contamination due to environmental sources. The insulation used for the Safety Injection System is fiberglass insulation designed to meet the requirements of Regulatory Guide 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel." Therefore, halide contamination due to leaching of contaminants from insulation is not expected to occur.

A large buildup of halide contamination increases the probability of cracking due to stress corrosion cracking which has the potential to lead to loss of component intended function. As explained below, significant halide contamination of stainless steel piping, piping components, and piping elements exposed to outdoor air or exposed to air which has recently been introduced into buildings is not expected at BBS. Additionally, an elevated temperature increases the likelihood of cracking. Experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steel exposed to an outdoor air environment can crack at temperatures as low as 104°F to 120°F, depending on humidity, component surface temperature, and contaminant concentration and composition. The highest temperatures recorded at BBS over the 10-year period between June 1, 2001 and June 1, 2012 were 94.4°F at Byron Station and 98.2°F at Braidwood Station. A review of historical temperature data since construction for areas surrounding BBS indicates that temperatures rarely exceed 100°F. UFSAR Section 2.3.2.1.2 identifies long-term average temperatures of approximately 50°F for BBS. Therefore, stress corrosion cracking of stainless steel piping, piping components, and piping elements exposed to outdoor air or exposed to air which has recently been introduced into buildings is not expected to occur at BBS.

Halide surface contamination is significant in areas where there are greater concentrations of halides such as near the seacoast where salt spray is prevalent or near industrial facilities. Byron and Braidwood Stations are not located near the seacoast. They are located inland, in central Illinois. Both Byron and Braidwood are located in areas where industrial halide concentrations are low, since they are located in rural areas with no heavy industry nearby.

Byron and Braidwood Stations are not located within one half mile of a highway treated with salt in the wintertime. Major highways in the vicinity of Byron Station include interstate I-90 northeast of the site approximately 11 miles away, interstate I-39 east of the site approximately 11 miles away, and interstate I-88 south of the site approximately 14 miles away. The only major highway in the vicinity of Braidwood Station is interstate I-55 northwest of the site approximately three quarters of a mile away.

The cooling towers at Byron Station are treated with sodium hypochlorite. However, chloride contamination ***resulting in the loss of the intended function*** of stainless steel components located outdoors is not expected since the ***components are covered by insulation. The insulation acts as a barrier to prevent the accumulation of halides on the component surface. Additionally, the*** prevailing wind direction is west to east and is directed away from the site. Braidwood Station does not have cooling towers.

Halide contamination of stainless steel components from soil containing more than trace chlorides or from agricultural sources is not expected. However, should halide contamination occur, any potential buildup of halide contamination would be gradual and such contamination would be periodically washed away by rainfall or snow. Cracking due to cumulative build up of halides on stainless steel components located outdoors at BBS has not been experienced and is not expected. The smooth surfaces of the stainless steel components aid the removal of potential halide contamination. Therefore, the concentration of contaminants necessary to initiate stress corrosion cracking of stainless steel is not expected.

Based on the collective environmental conditions, as described above, and confirmed by a review of operating experience, cracking due to stress corrosion cracking of stainless steel components exposed to outdoor air is not expected to occur. Therefore, aging management activities for cracking due to stress corrosion cracking for stainless steel components exposed to outdoor air are not required for the period of extended operation.

As a result of the responses to RAI's 3.0.3-3 and B.2.1.23-1 provided in Enclosure A of this letter, LRA Table 3.2.1, Summary of Aging Management Evaluation for the Engineered Safety Features, pages 3.2-13, 3.2-14, and 3.2-31, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.2.1 Summary of Aging Management Evaluations for Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-4	Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor	Loss of material due to pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated	***Not Applicable.*** ~~Consistent with NUREG-1801. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of stainless steel piping, piping components, and piping elements exposed to air - outdoor.~~ ***There is no un-insulated stainless steel piping, piping components, piping elements, and tanks exposed to air – outdoor environment in the Emergency Safety Features systems.*** ***See 3.2.1-69 for insulated stainless steel piping, piping, components, and piping elements exposed to air – outdoor.*** See subsection 3.2.2.2.3.2.

Table 3.2.1 Summary of Aging Management Evaluations for Engineered Safety Features					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.2.1-7	Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated	***Not Applicable.*** ~~Based on the evaluation of the environmental conditions at BBS and a review of operating experience, cracking is not an applicable aging effect for the stainless steel piping, piping components, and piping elements exposed to air - outdoor.~~ ***There is no un-insulated stainless steel piping, piping components, piping elements, and tanks exposed to air – outdoor environment in the Emergency Safety Features systems.*** ***See 3.2.1-71 for insulated stainless steel piping, piping, components, and piping elements exposed to air – outdoor.*** See subsection 3.2.2.2.6.
3.2.1-69	***Insulated steel, stainless steel, copper alloy, or aluminum, piping, piping components, and tanks exposed to condensation, air-outdoor***	***Loss of material due to general (steel, and copper alloy only), pitting, and crevice corrosion***	***Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks," (for tanks only)***	***No***	***Consistent with LR-ISG-2012-02. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of stainless steel insulated piping, piping components, and piping elements exposed to air - outdoor in the Safety Injection System.***

Table 3.2.1 Summary of Aging Management Evaluations for Engineered Safety Features

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-71	*Insulated stainless steel, aluminum, or copper alloy (> 15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor*	*Cracking due to stress corrosion cracking*	*Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks," (for tanks only)*	*No*	*Based on the evaluation of the environmental conditions and physical configurations at BBS, cracking is not an applicable aging effect for the Engineered Safety Features Systems stainless steel insulated piping, piping components, and piping elements exposed to air - outdoor.* *See subsection 3.2.2.2.6.*

As a result of the responses to RAI's 3.0.3-2 and 3.0.3-3 provided in Enclosure A of this letter, LRA Table 3.2.2-4, Safety Injection System, pages 3.2-50 through 3.2-57, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.2.2-4 Safety Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	***Pressure Boundary***	***Stainless Steel***	***Air - Outdoor (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***V.D1.E-403***	***3.2.1-69***	***A***
				None	***None***	***V.D1.E-406***	***3.2.1-71***	***I, 2***
			Condensation (Internal)	***Loss of Material***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***V.D1.EP-81***	***3.2.1-48***	***A***
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	~~Air - Outdoor (External)~~	~~Loss of Material~~	~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~V.D1.EP-107~~	~~3.2.1-4~~	~~A~~
				~~None~~	~~None~~	~~V.D1.EP-103~~	~~3.2.1-7~~	~~I, 2~~

Table 3.2.2-4 Safety Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Safety Injection Pump Oil Reservoir)	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	V.D1.E-28	3.2.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	V.E.E-44	3.2.1-40	A
			Lubricating Oil (Internal)	***Loss of Coating Integrity***	***Lubricating Oil Analysis (B.2.1.26)***			***H, 5***
				Loss of Material	Lubricating Oil Analysis (B.2.1.26)	V.D1.EP-77	3.2.1-49	C
					One-Time Inspection (B.2.1.20)	V.D1.EP-77	3.2.1-49	C

Plant Specific Notes:

2. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for ***insulated*** stainless steel in an Air-Outdoor environment. ***Per NACE SP0198-2010, SCC can occur under insulation when the evaporation of water, due to contact with hot stainless steel, causes the concentration of halides on the surface of stainless steel components. The potential sources of halide contamination are leachable halides from insulating materials and/or external environmental sources. The insulating materials for this component do not contain leachable halides. External sources of halides are not a significant contributor to the occurrence of SCC as the insulation shelters the component external surface. In addition, since this is not hot piping, the concentration of halides is not expected to occur. Therefore, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for insulated stainless steel in an Air-Outdoor environment. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program will be used to manage loss of material of this component.*** For more information see LRA Section 3.3.2.2.3.

5. The aging effects for metallic components with an internal coating or lining in a lubricating oil environment include loss of coating integrity. The Lubricating Oil Analysis (B.2.1.26) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a lubricating oil environment.

As a result of the responses to RAI's 3.0.3-2 and B.2.1.28-1 provided in Enclosure A of this letter LRA Section 3.3.2.1.12, Fire Protection System, pages 3.3-15 through 3.3-17, is revised as shown below. Additions are indicated with ***bolded italics***.

3.3.2.1.12 Fire Protection System

Materials

The materials of construction for the Fire Protection System components are:

- Aluminum Alloy
- Carbon Steel
- ***Carbon Steel (with internal lining or coating)***
- Carbon and Low Alloy Steel Bolting
- Ceramic Fiber
- Concrete Block
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Ductile Cast Iron
- Elastomers
- Galvanized Steel
- Galvanized Steel Bolting
- Gray Cast Iron
- Grout
- Gypsum
- Mineral Fiber
- Pyrocrete
- Reinforced Concrete
- Soil, Rip-Rap, Sand, Gravel
- Stainless Steel
- Stainless Steel Bolting

Environments

The Fire Protection System components are exposed to the following environments:

- Air - Indoor Uncontrolled

- Air - Outdoor
- Air with Borated Water Leakage
- Air/Gas – Dry
- ***Concrete***
- Condensation
- Diesel Exhaust
- Raw Water
- Soil
- Waste Water

Aging Effect Requiring Management

The following aging effects associated with the Fire Protection System components require management:

- Concrete Cracking and Spalling
- Cracking
- Cracking, Loss of Material, and Loss of Bond
- Cumulative Fatigue Damage
- Hardening, Loss of Strength, and Loss of Sealing
- ***Loss of Coating Integrity***
- Loss of Form
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Section 3.3.2.1.15, Fuel Oil System, pages 3.3-19 and 3.3-20, is revised as shown below. Additions are indicated with ***bolded italics***.

3.3.2.1.15 Fuel Oil System

Materials

The materials of construction for the Fuel Oil System components are:

- Carbon Steel
- ***Carbon Steel (with internal lining or coating)***
- Carbon and Low Alloy Steel Bolting
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Aging Effect Requiring Management

The following aging effects associated with the Fuel Oil System components require management:

- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, the Materials section of LRA Section 3.3.2.1.20, Radwaste System, pages 3.3-24 and 3.3-25, is revised as shown below. Additions are indicated with ***bolded italics***.

3.3.2.1.20 Radwaste System

Materials

The materials of construction for the Radwaste System components are:

- Carbon Steel
- ***Carbon Steel (with internal lining or coating)***
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Carbon or Low Alloy Steel with Titanium Cladding
- Copper Alloy with less than 15% Zinc
- Ductile Cast Iron
- Glass
- Gray Cast Iron
- Stainless Steel

Aging Effect Requiring Management

The following aging effects associated with the Radwaste System components require management:

- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload

As a result of the responses to RAI's 3.0.3-2 and 3.0.3-3 provided in Enclosure A of this letter, LRA Section 3.3.2.1.22, Service Water System, pages 3.3-27 and 3.3-28, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

3.3.2.1.22 Service Water System

Materials

The materials of construction for the Service Water System components are:

- Aluminum Alloy – (Byron only)
- Carbon Steel
- ***Carbon Steel (with internal lining or coating)***
- Carbon Steel with Polymer Lining
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Copper Alloy (<15% Zinc) Cladding
- Carbon or Low Alloy Steel with Nickel Alloy Cladding
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Copper Alloy with 15% Zinc or More
- ***Copper Alloy with 15% Zinc or More (with internal coating or lining)***
- Copper Alloy with less than 15% Zinc
- Elastomers - (Braidwood only)
- Glass
- Gray Cast Iron
- Polymers
- Stainless Steel
- ***Stainless Steel (with internal coating or lining)***
- Stainless Steel Bolting
- Titanium Alloy - (Braidwood only)

Environments

The Service Water System components are exposed to the following environments:

- Condensation ~~- (Byron only)~~

Aging Effect Requiring Management

The following aging effects associated with the Service Water System components require management:

- Cracking

- Cumulative Fatigue Damage
- Hardening and Loss of Strength
- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

As a result of the response to RAI 2.1.23-1 provided in Enclosure A of this letter, LRA Section 3.3.2.2.3, pages 3.3-31 through 3.3-33, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

3.3.2.2.3 Cracking due to Stress Corrosion Cracking

Cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, piping elements and tanks exposed to outdoor air. The possibility of cracking also extends to components exposed to air which has recently been introduced into buildings, i.e., components near intake vents. Cracking is only known to occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. Condensation or deliquescence should generally be assumed to be possible. Applicable outdoor air environments (and associated indoor air environments) include, but are not limited to, those within approximately 5 miles of a saltwater coastline, those within 1/2 mile of a highway which is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources. This item is applicable for the environments described above.

GALL AMP XI.M36, "External Surfaces Monitoring" is an acceptable method to manage the aging effect. The applicant may demonstrate that this item is not applicable by describing the outdoor air environment present at the plant and demonstrating that external chloride stress corrosion cracking is not expected. The GALL Report recommends further evaluation to determine whether an adequate aging management program is used to manage this aging effect based on the environmental conditions applicable to the plant and ASME Code Section XI requirements applicable to the components.

The only stainless steel components exposed to outdoor air in the Auxiliary Systems are (1) portions of the exhaust lines for the diesel generators and diesel-driven pumps in the Emergency Diesel Generators & Auxiliaries System, Fire Protection System, and Service Water System (Byron only); (2) portions of the Service Water System and Demineralized Water System located within vaults or pits; ~~and~~ (3) an insulated length of Auxiliary Building Ventilation System piping that provides a vent path from the refueling water storage tank to the Auxiliary Building filtered vent header***; and (4) Service Water System stainless steel piping and valve body associated with the essential service water cooling tower gear reducer assembly (Byron only).*** There are no stainless steel tanks exposed to an outdoor air environment in the scope of license renewal at Byron and Braidwood Stations (BBS). Stress corrosion cracking of the diesel exhaust line components due to halide contamination is not expected to occur, however, should cracking occur the function of these components would not be affected since an exhaust path for the diesels would still be provided. ***To confirm that cracking does not occur, the One Time Inspection program (B.2.1.20) will be used to assess the stainless steel components with direct exposure to outdoor air conditions. This includes the essential service water makeup pump diesel exhaust lines (Byron Only), as the other diesel systems stainless steel components are insulated or otherwise sheltered from outdoor conditions.*** In addition to the diesel generator and diesel-driven fire pump exhaust lines; stainless steel portions of the Service Water System ***(with the exception of the stainless steel components associated with the essential service water cooling tower gear reducer assembly)***, the Demineralized Water System (Byron only), and the Auxiliary Building Ventilation System are considered to have an outdoor air external environment. However, these components are either contained in vaults or pits (Service Water System and

Demineralized Water System), or are insulated (Auxiliary Building Ventilation System) and, therefore, the surface of these components is protected from potential halide contamination from environmental sources.

Thermal insulation is utilized for the Auxiliary Building Ventilation System and Emergency Diesel Generators & Auxiliaries System piping exposed to outdoor air. The insulation exposed to outdoor air for the Emergency Diesel Generators & Auxiliaries System is located in a pipe chase and, as such, is not directly exposed to weather effects that could cause wetting and potential leaching of contaminants. The insulation used for the Auxiliary Building Ventilation System is fiberglass insulation designed to meet the Regulatory Guide 1.36, “Nonmetallic Thermal Insulation for Austenitic Stainless Steel” requirements for leachable halide levels. Therefore, halide contamination due to the leaching of contaminants from insulation is not expected to occur for insulated piping in the Auxiliary Building Ventilation System and the Emergency Diesel Generators & Auxiliaries System.

A large buildup of halide contamination increases the probability of cracking due to stress corrosion cracking which has the potential to lead to loss of component intended function. As explained below, significant halide contamination of stainless steel piping, piping components, and piping elements exposed to outdoor air or exposed to air which has recently been introduced into buildings is not expected at BBS. Additionally, an elevated temperature increases the likelihood of cracking. Experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steel exposed to an outdoor air environment can crack at temperatures as low as 104°F to 120°F, depending on humidity, component surface temperature, and contaminant concentration and composition. The highest temperatures recorded at BBS over the 10-year period between June 1, 2001 and June 1, 2012 were 94.4°F at Byron Station and 98.2°F at Braidwood Station. A review of historical temperature data since construction for areas surrounding BBS indicates that temperatures rarely exceed 100°F. UFSAR Section 2.3.2.1.2 identifies long-term average temperatures of approximately 50°F for BBS. Therefore, stress corrosion cracking of stainless steel piping, piping components, and piping elements exposed to outdoor air or exposed to air which has recently been introduced into building is not expected to occur at BBS.

Halide surface contamination is significant in areas where there are greater concentrations of halides such as near the seacoast where salt spray is prevalent or near industrial facilities. Byron and Braidwood Stations are not located near the seacoast. They are located inland, in central Illinois. Both Byron and Braidwood are located in areas where industrial halide concentrations are low, since they are located in rural areas with no heavy industry nearby.

Byron and Braidwood Stations are not located within one half mile of a highway treated with salt in the wintertime. Major highways in the vicinity of Byron Station include interstate I-90 northeast of the site approximately 11 miles away, interstate I-39 west of the site approximately 11 miles away, and interstate I-88 south of the site approximately 14 miles away. The only major highway in the vicinity of Braidwood Station is interstate I-55 northwest of the site approximately three quarters of a mile away.

The cooling towers at Byron Station are treated with sodium hypochlorite. However, chloride contamination ***resulting in the loss of the intended function*** of stainless steel components located outdoors is not expected since the prevailing wind direction is west to east and is directed away from the site. Braidwood Station does not have cooling towers.

Halide contamination of stainless steel components from soil containing more than trace chlorides or from agricultural sources is not expected. However, should halide contamination occur, any potential buildup of halide contamination would be gradual and such contamination would be periodically washed away by rainfall or snow. Cracking due to cumulative build up of halides on stainless steel components located outdoors at BBS has not been experienced and is not expected. The smooth surfaces of the stainless steel components aid the removal of potential halide contamination. Therefore, the concentration of contaminants necessary to initiate stress corrosion cracking of stainless steel is not expected.

Based on the collective environmental conditions, as described above, and confirmed by a review of operating experience, cracking due to stress corrosion cracking of stainless steel components exposed to outdoor air is not expected to occur. T~~herefore~~ ~~activities for cracking due to stress corrosion cracking for are not required for the period of extended operation~~. ***Regardless, the External Surfaces Monitoring of Mechanical Components aging management program is used to monitor liquid-filled stainless steel components directly exposed to an outdoor-air environment for cracking due to stress corrosion cracking. Components which are insulated or which are located in enclosed underground pits are shielded from accumulation of potential contaminants in the environment, and are therefore not susceptible to stress corrosion cracking. Stress corrosion cracking of the diesel exhaust line components due to halide contamination is not expected to occur, however, should cracking occur the intended function of these components would not be affected since an exhaust path for the diesels would still be provided. The One –Time Inspection aging management program is used to verify that gas-filled stainless steel components directly exposed to an outdoor air environment do not exhibit cracking due to stress corrosion cracking.***

As a result of the responses to RAI's 3.0.3-3 and RAI B.2.1.23-1 provided in Enclosure A of this letter, LRA Table 3.3.1, Summary of Aging Management Evaluations for the Auxiliary Systems, pages 3.3-37 and 3.3-88, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.3.1-4	Stainless steel Piping, piping components, and piping elements; tanks exposed to Air – outdoor	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated	***Consistent with NUREG-1801. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage cracking of stainless steel piping, piping components, and piping elements exposed to air-outdoor in the Service Water system.*** ***The One-Time Inspection (B.2.1.20) program has been substituted and will be used to manage cracking of stainless steel piping, piping components, and piping elements exposed to air-outdoor with diesel exhaust internal environment in the Service Water System.*** ~~Based on the evaluation of the environmental conditions at BBS and a review of operating experience, cracking is not an applicable aging effect for stainless steel piping, piping components, and piping elements exposed to air - outdoor.~~ See subsection 3.3.2.2.3.

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-132	***Insulated steel, stainless steel, copper alloy, aluminum, or copper alloy (> 15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor***	***Loss of material due to general (steel, and copper alloy only), pitting, and crevice corrosion; cracking due to stress corrosion cracking (aluminum, stainless steel and copper alloy (>15% Zn) only)***	***Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks" (for tanks only)***	***No***	***The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of steel and stainless steel insulated piping, piping components, and piping elements, and tanks exposed to air - outdoor and condensation in the Auxiliary Building Ventilation System, Chemical & Volume Control System, Chilled Water System, Fire Protection System, and Service Water System.*** ***Based on the evaluation of the environmental conditions and physical configurations at BBS, cracking is not an applicable aging effect for the stainless steel insulated piping, piping components, and piping elements exposed to air – outdoor or condensation in the Auxiliary Building Ventilation System, Chemical & Volume Control System, Chilled Water System, and Fire Protection System.*** ***See subsection 3.3.2.2.3.***

As a result of the response to RAI 3.0.3-3 provided in Enclosure A of this letter, LRA Table 3.3.2-1, Auxiliary Building Ventilation System, pages 3.3-96 and 3.3-102, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-1 Auxiliary Building Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated ~~P~~***p***iping, piping components, and piping elements	Structural Support	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	~~VII.H1.A-24~~ ***VII.G.A-405***	~~3.3.1-80~~ ***3.3.1-132***	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-23	3.3.1-89	A
		Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	~~VII.F2.AP-221~~ ***VII.G.A-405***	~~3.3.1-6~~ ***3.3.1-132***	A
				None	None	~~VII.G.AP-209~~ ***VII.G.A-405***	~~3.3.1-4~~ ***3.3.1-132***	I, 4
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-273	3.3.1-95	A

Table 3.3.2-1 Auxiliary Building Ventilation System (Continued)

Plant Specific Notes:

4. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking is not an applicable aging effect for ***insulated*** stainless steel in an Air-Outdoor environment. ***Per NACE SP0198-2010, SCC can occur under insulation when the evaporation of water, due to contact with hot stainless steel, causes the concentration of halides on the surface of stainless steel components. The potential sources of halide contamination are leachable halides from insulating materials and/or external environmental sources. The insulating materials for this component do not contain leachable halides. External sources of halides are not a significant contributor to the occurrence of SCC as the insulation shelters the component external surface. In addition, since this is not hot piping, the concentration of halides is not expected to occur. Therefore, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for insulated stainless steel in an Air-Outdoor environment. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program will be used to manage loss of material of this component.*** For more information see LRA Section 3.3.2.2.3.

As a result of the response to RAI 3.0.3-3 provided in Enclosure A of this letter, LRA Table 3.3.2-2, Chemical & Volume Control System, pages 3.3-118, 3.3-121, 3.3-126, 3.3-127, and 3.3-133 is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-2 Chemical & Volume Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	***Leakage Boundary***	***Carbon Steel***	***Condensation (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A, 7***
			Waste Water (Internal)	***Loss of Material***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.E5.AP-281***	***3.3.1-91***	***A***
		Stainless Steel	***Condensation (External)***	***None***	***None***	***VII.I.A-405***	***3.3.1-132***	***I, 8***
				Loss of Material	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A, 7***
			Waste Water (Internal)	***Loss of Material***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.E5.AP-278***	***3.3.1-95***	***A***

Table 3.3.2-2 Chemical & Volume Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Pump Casing (BTR Chiller)	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.E1.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A, 7***
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
Insulated Tanks (Chiller Surge)	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.E1.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A, 7***
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A

Table 3.3.2-2 Chemical & Volume Control System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Valve Body	*Leakage Boundary*	*Carbon Steel*	*Condensation (External)*	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A, 7*
			Waste Water (Internal)	*Loss of Material*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)*	*VII.E5.AP-281*	*3.3.1-91*	*A*

Table 3.3.2-2 Chemical & Volume Control System (Continued)

Plant Specific Notes: (continued)

7. Insulated components are associated with the boron thermal regeneration chiller subsystem. This portion of the system is normally not in-service and therefore contains a waste water (internal) environment. However, should the system be returned to service, the internal chilled fluid environment could result in condensation on the external surfaces of the SSCs.

8. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking is not an applicable aging effect for insulated stainless steel in a Condensation external environment. Per NACE SP0198-2010, SCC can occur under insulation when the evaporation of water, due to contact with hot stainless steel, causes the concentration of halides on the surface of stainless steel components. The potential sources of halide contamination are leachable halides from insulating materials and/or external environmental sources. The insulating materials for this component do not contain leachable halides. External sources of halides are not a significant contributor to the occurrence of SCC as the component is located indoors. In addition, since this is not hot piping, the concentration of halides is not expected to occur. Therefore, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for insulated stainless steel in a Condensation external environment. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program will be used to manage loss of material of this component.

As a result of the response to RAI 3.0.3-3 provided in Enclosure A of this letter, LRA Table 3.3.2-3, Chilled Water System, page 3.3-143 through 3.3-149, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-3 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	***Leakage Boundary***	***Carbon Steel***	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	***Loss of Material***	***Closed Treated Water Systems (B.2.1.12)***	***VII.C2.AP-202***	***3.3.1-45***	***A***
		Stainless Steel	***Air with Borated Water Leakage (External)***	***None***	***None***	***VII.J.AP-18***	***3.3.1-120***	***A***
			Condensation (External)	***None***	***None***	***VII.I.A-405***	***3.3.1-132***	***I, 2***
				Loss of Material	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	***Loss of Material***	***Closed Treated Water Systems (B.2.1.12)***	***VII.C2.A-52***	***3.3.1-49***	***A***

Table 3.3.2-3 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	*Pressure Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Closed Cycle Cooling Water (Internal)	*Loss of Material*	*Closed Treated Water Systems (B.2.1.12)*	*VII.C2.AP-202*	*3.3.1-45*	*A*
		Stainless Steel	*Air with Borated Water Leakage (External)*	*None*	*None*	*VII.J.AP-18*	*3.3.1-120*	*A*
			Condensation (External)	*None*	*None*	*VII.I.A-405*	*3.3.1-132*	*I, 2*
				Loss of Material	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Closed Cycle Cooling Water (Internal)	*Loss of Material*	*Closed Treated Water Systems (B.2.1.12)*	*VII.C2.A-52*	*3.3.1-49*	*A*

Table 3.3.2-3 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Pump Casing (Auxiliary Building Chilled Water Pump)	Leakage Boundary	Gray Cast Iron	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
					Selective Leaching (B.2.1.21)	VII.C2.A-50	3.3.1-72	A
Insulated Pump Casing (Control Room Chilled Water Pump)	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A

Table 3.3.2-3 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Pump Casing (Primary Containment Chilled Water Pump)	Leakage Boundary	Gray Cast Iron	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
Insulated Tanks - (Air Separator - Control Room)	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
Insulated Tanks - (Air Separator With Strainer - Containment and Auxiliary Building)	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A

Table 3.3.2-3 Chilled Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Tanks - (Chilled Water Tank - Containment and Auxiliary Building)	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
Insulated Tanks - (Control Room Chilled Water System Standpipe)	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A

Table 3.3.2-3 **Chilled Water System** **(Continued)**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Valve Body	*Leakage Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Closed Cycle Cooling Water (Internal)	*Loss of Material*	*Closed Treated Water Systems (B.2.1.12)*	*VII.C2.AP-202*	*3.3.1-45*	*A*
		Stainless Steel	*Air with Borated Water Leakage (External)*	*None*	*None*	*VII.J.AP-18*	*3.3.1-120*	*A*
			Condensation (External)	*None*	*None*	*VII.I.A-405*	*3.3.1-132*	*I, 2*
				Loss of Material	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Closed Cycle Cooling Water (Internal)	*Loss of Material*	*Closed Treated Water Systems (B.2.1.12)*	*VII.C2.A-52*	*3.3.1-49*	*A*

Table 3.3.2-3 **Chilled Water System** **(Continued)**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Valve Body	*Pressure Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Closed Cycle Cooling Water (Internal)	*Loss of Material*	*Closed Treated Water Systems (B.2.1.12)*	*VII.C2.AP-202*	*3.3.1-45*	*A*
		Stainless Steel	*Air with Borated Water Leakage (External)*	*None*	*None*	*VII.J.AP-18*	*3.3.1-120*	*A*
			Condensation (External)	*None*	*None*	*VII.I.A-405*	*3.3.1-132*	*I, 2*
				Loss of Material	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Closed Cycle Cooling Water (Internal)	*Loss of Material*	*Closed Treated Water Systems (B.2.1.12)*	*VII.C2.A-52*	*3.3.1-49*	*A*

Table 3.3.2-3 Chilled Water System (Continued)

Plant Specific Notes:

2. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking is not an applicable aging effect for insulated stainless steel in a Condensation external environment. Per NACE SP0198-2010, SCC can occur under insulation when the evaporation of water, due to contact with hot stainless steel, causes the concentration of halides on the surface of stainless steel components. The potential sources of halide contamination are leachable halides from insulating materials and/or external environmental sources. The insulating materials for this component do not contain leachable halides. External sources of halides are not a significant contributor to the occurrence of SCC as the component is located indoors. In addition, since this is not hot piping, the concentration of halides is not expected to occur. Therefore, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for insulated stainless steel in a Condensation external environment. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program will be used to manage loss of material of this component.

As a result of the response to RAI 3.0.3-3 provided in Enclosure A of this letter, LRA Table 3.3.2-11, Emergency Diesel Generators & Auxiliaries System, pages 3.3-206 through 3.3-217, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-11 Emergency Diesel Generator & Auxiliaries System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.H1.A-24	3.3.1-80	A, ***10***
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.H2.AP-202	3.3.1-45	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-23	3.3.1-89	A
			Diesel Exhaust (Internal)	Cumulative Fatigue Damage	TLAA			H, 5
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-88	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H2.AP-105	3.3.1-70	A
					One-Time Inspection (B.2.1.20)	VII.H2.AP-105	3.3.1-70	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-127	3.3.1-97	A
					One-Time Inspection (B.2.1.20)	VII.H2.AP-127	3.3.1-97	A

Table 3.3.2-11 Emergency Diesel Generator & Auxiliaries System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.H2.AP-221	3.3.1-6	A, ***10***
				~~None~~	~~None~~	~~VII.H2.AP-209~~	~~3.3.1-4~~	~~I, 6~~
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-49	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-273	3.3.1-95	A
			Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-128	3.3.1-83	A
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-88	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H2.AP-136	3.3.1-71	A
					One-Time Inspection (B.2.1.20)	VII.H2.AP-136	3.3.1-71	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.20)	VII.H2.AP-138	3.3.1-100	A

Table 3.3.2-11 Emergency Diesel Generator & Auxiliaries System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Silencer/Muffler	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-78	3.3.1-78	A***, 10***
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-23	3.3.1-89	A
			Diesel Exhaust (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-88	A

Plant Specific Notes:

6. ***Not Used*** ~~Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking is not an applicable aging effect for stainless steel in an Air-Outdoor environment. For more information see LRA Section 3.3.2.2.3.~~

10. Portions of the emergency diesel generator exhaust with an Air-Outdoor (external) environment are insulated and located within an enclosure on top of the Auxiliary Building roof. This enclosure contains louvers open to the outside air environment, and for this reason, the Air-Outdoor (external) environment was selected. However, the enclosure provides shelter and protection to the insulated diesel generator exhaust components and protects them from precipitation, cooling tower drift, and wind effects. Therefore, condensation underneath the insulation is not a concern.

As a result of the responses to RAI's 3.0.3-2, 3.0.3-3, and B.2.1.28-1 provided in Enclosure A of this letter, LRA Table 3.3.2-12, Fire Protection System, pages 3.3-224 through 3.3-235, is revised as shown below. Only those line items affected by the revision are shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-12 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	***Pressure Boundary***	***Carbon Steel***	***Air - Outdoor (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.G.A-405***	***3.3.1-132***	***A***
			Diesel Exhaust (Internal)	***Cumulative Fatigue Damage***	***TLAA***			***H, 10***
				Loss of Material	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.H2.AP-104***	***3.3.1-88***	***A***
		Stainless Steel	***Air - Outdoor (External)***	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.G.A-405***	***3.3.1-132***	***A***
				None	***None***	***VII.G.A-405***	***3.3.1-132***	***I, 11***
			Diesel Exhaust (Internal)	***Cracking***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.H2.AP-128***	***3.3.1-83***	***A***
				Cumulative Fatigue Damage	***TLAA***			***H, 10***
				Loss of Material	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.H2.AP-104***	***3.3.1-88***	***A***

Table 3.3.2-12 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
					Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-58	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-78	3.3.1-78	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
					Fire Protection (B.2.1.15)	VII.G.AP-150	3.3.1-58	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-4	3.3.1-121	A
			Concrete (External)	***Loss of Material***	***Buried and Underground Piping (B.2.1.28)***	***VII.G.AP-198***	***3.3.1-106***	***B***
			Condensation (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-23	3.3.1-89	A
			Condensation (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.G.A-23	3.3.1-89	A
		Stainless Steel	Air – Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air – Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.G.AP-221	3.3.1-6	A
				~~None~~	~~None~~	~~VII.G.AP-209~~	~~3.3.1-4~~	~~I, 11~~

Table 3.3.2-12 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Foam Concentrate Storage)	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Fire Water System (B.2.1.16)***			***H, 13***
				Loss of Material	Fire Water System (B.2.1.16)	VII.G.A-33	3.3.1-64	C

Plant Specific Notes:

11. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for ***insulated*** stainless steel in an Air-Outdoor environment. ***Per NACE SP0198-2010, SCC can occur under insulation when the evaporation of water, due to contact with hot stainless steel, causes the concentration of halides on the surface of stainless steel components. The potential sources of halide contamination are leachable halides from insulating materials and/or external environmental sources. The insulating materials for this component do not contain leachable halides. External sources of halides are not a significant contributor to the occurrence of SCC as the insulation shelters the component external surface. In addition, since this is not hot piping, the concentration of halides is not expected to occur. Therefore, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for insulated stainless steel in an Air-Outdoor environment. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program will be used to manage loss of material of this component.***

13. The aging effects for metallic components with an internal coating or lining in a raw water environment include loss of coating integrity. The Fire Water System (B.2.1.16) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a raw water environment.

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Table 3.3.2-15, Fuel Oil System, page 3.3-246, is revised as shown below. Only those line items affected by the revision are shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-15 Fuel Oil System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Diesel Generator Fuel Oil Storage Tanks)	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Fuel Oil (Internal)	***Loss of Coating Integrity***	***Fuel Oil Chemistry (B.2.1.18)***			***H, 1***
				Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-70	A
					One-Time Inspection (B.2.1.20)	VII.H1.AP-105	3.3.1-70	A

Plant Specific Notes:

~~None~~

1. The aging effects for metallic components with an internal coating or lining in a fuel oil environment include loss of coating integrity. The Fuel Oil Chemistry (B.2.1.18) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a fuel oil environment.

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Table 3.3.2-20, Radwaste System, pages 3.3-289, 3.3-296, 3.3-299, 3.3-300, and 3.3-303, is revised as shown below. Only those line items affected by the revision are shown below. Additions are indicated with ***bolded italics***.

Table 3.3.2-20 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
		Carbon Steel (with internal coating or lining)	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Waste Water (Internal)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***			***H, 3***
				Loss of Material	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.E5.AP-281***	***3.3.1-91***	***A***

Table 3.3.2-20 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Caustic Day Tank)	Leakage Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Waste Water (Internal)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***			***H, 3***
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
Tanks (Sulfuric Acid Day Tank)	Leakage Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Waste Water (Internal)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***			***H, 3***
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A

Table 3.3.2-20 Radwaste System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
		Carbon Steel (with internal coating or lining)	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Waste Water (Internal)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25***			***H, 3***
				Loss of Material	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.E5.AP-281***	***3.3.1-91***	***A***

Plant Specific Notes:

3. The aging effects for metallic components with an internal coating or lining in a waste water environment include loss of coating integrity. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a waste water environment.

As a result of the responses to RAI's 3.0.3-2, 3.0.3-3, B.2.1.23-1, and B.2.1.28-1 provided in Enclosure A of this letter, LRA Table 3.3.2-22, Service Water System, pages 3.3-317 through 3.3-351, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (Auxiliary Building HVAC Refrigeration Unit Condenser) Tube Side Components	Leakage Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
			Waste Water (Internal) - (Byron only)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***			***H, 10***
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	C
Heat Exchanger - (Chilled Water Primary Containment Refrigeration Unit Condenser) Tube Side Components	Leakage Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (Computer Room AC Condenser Coil – ***Braidwood only***) Tube Side Components	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - (Computer Room AC Condenser Coil – Byron only) Tube Side Components	***Leakage Boundary***	***Carbon Steel (with internal coating or lining)***	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.C1.AP-183***	***3.3.1-38***	***A***
Heat Exchanger - (Control Room Refrigeration Unit Condenser) Tube Sheet	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - (Control Room Refrigeration Unit Condenser) Tube Side Components	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (Diesel-Driven SX Makeup Pump Jacket Water - Byron only) Tube Sheet	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Closed Cycle Cooling Water (External)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-189	3.3.1-46	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - (Diesel-Driven SX Makeup Pump Jacket Water - Byron only) Tube Side Components	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - (Diesel-Driven SX Makeup Pump Right Angle Gear Box Lube Oil - Byron only) Tube Sheet	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.H2.AP-131	3.3.1-98	A
					One-Time Inspection (B.2.1.20)	VII.H2.AP-131	3.3.1-98	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - (Diesel-Driven SX Makeup Pump Right Angle Gear Box Lube Oil - Byron only) Tube Side Components	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (EDG Jacket Water Upper/Lower Cooler) Tube Sheet	Pressure Boundary	Copper Alloy with 15% Zinc or More ***(with internal coating or lining)***	Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-38	A
					Selective Leaching (B.2.1.21)	VII.C1.A-66	3.3.1-72	A
Heat Exchanger - (EDG Jacket Water Upper/Lower Cooler) Tube Side Components	Pressure Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - (RCFC Essential Service Water Coils ***– Braidwood only***) Tube Sheet	Pressure Boundary	Stainless Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-41	C
Heat Exchanger - (RCFC Essential Service Water Coils – Byron only) Tube Sheet	***Pressure Boundary***	***Stainless Steel (with internal coating or lining)***	***Raw Water (Internal)***	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.H2.AP-55***	***3.3.1-41***	***C***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (RCFC Essential Service Water Coils ***– Braidwood only***) Tube Side Components	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-179	3.3.1-38	A
		Stainless Steel	Air with Borated Water Leakage (External)	None	None	VII.J.AP-18	3.3.1-120	C
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.H2.AP-55	3.3.1-41	C
Heat Exchanger - (RCFC Essential Service Water Coils – Byron only) Tube Side Components	***Pressure Boundary***	***Carbon Steel (with internal coating or lining)***	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.C1.AP-179***	***3.3.1-38***	***A***
		Stainless Steel (with internal coating or lining)	***Air with Borated Water Leakage (External)***	***None***	***None***	***VII.J.AP-18***	***3.3.1-120***	***C***
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.H2.AP-55***	***3.3.1-41***	***C***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (Radwaste & RSD Control Room HVAC Condenser) Tube Side Components	Leakage Boundary	Carbon Steel ***(with internal coating or lining)***	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - ([CV, SI, RH, CS, SX] Pump Cubicle Cooler **–** ***Braidwood only***) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - ([***1A, 1B, and 2A*** CV, ***1A and 2B*** SI, RH, ***1A, 1B, and 2A*** CS, SX] Pump Cubicle Cooler **–** ***Byron only***) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - ([2B CV, 1B and 2A SI, RH, 2B CS, SX] Pump Cubicle Cooler – Byron only) Tube Sheet	***Pressure Boundary***	***Carbon Steel (with internal coating or lining)***	***Raw Water (Internal)***	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.C1.AP-183***	***3.3.1-38***	***A***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - ([CV, SI, RH, CS, SX] Pump Cubicle Cooler **– *Braidwood only***) Tube Side Components	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger - ([1A, 1B, and 2A CV, 1A and 2B SI, RH, 1A, 1B, and 2A CS, SX] Pump Cubicle Cooler – Byron only) Tube Side Components	***Pressure Boundary***	***Carbon Steel***	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Raw Water (Internal)	***Loss of Material***	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.C1.AP-183***	***3.3.1-38***	***A***
Heat Exchanger - ([2B CV, 1B and 2A SI, RH, 2B CS, SX] Pump Cubicle Cooler – Byron only) Tube Side Components	***Pressure Boundary***	***Carbon Steel (with internal coating or lining)***	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Raw Water (Internal)	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 9***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VII.C1.AP-183***	***3.3.1-38***	***A***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	*Leakage Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Raw Water (Internal)	*Loss of Material*	*Open-Cycle Cooling Water System (B.2.1.11)*	*VII.C1.AP-183*	*3.3.1-38*	*C*
	Pressure Boundary	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Raw Water (Internal)	*Loss of Material*	*Open-Cycle Cooling Water System (B.2.1.11)*	*VII.C1.AP-183*	*3.3.1-38*	*C*

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Strainer Body	Leakage Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	C
	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VII.I.A-77~~	~~3.3.1-78~~	~~A~~
			Condensation (External)	***Loss of Material***	***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	***VII.I.A-405***	***3.3.1-132***	***A***
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	C

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Valve Body	*Leakage Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Raw Water (Internal)	*Loss of Material*	*Open-Cycle Cooling Water System (B.2.1.11)*	*VII.C1.AP-183*	*3.3.1-38*	*C*
	Pressure Boundary	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VII.I.A-79*	*3.3.1-9*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VII.I.A-405*	*3.3.1-132*	*A*
			Raw Water (Internal)	*Loss of Material*	*Open-Cycle Cooling Water System (B.2.1.11)*	*VII.C1.AP-183*	*3.3.1-38*	*C*

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Air - Outdoor (External) - (Byron only)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.I.AP-284	3.3.1-109x	B
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	C
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
		Carbon Steel (with internal coating or lining)	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Waste Water (Internal)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***			***H, 10***
				Loss of Material	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.E5.AP-281***	***3.3.1-91***	***A***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Air - Outdoor (External)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.I.AP-284	3.3.1-109x	B
			Air - Outdoor (External) - (Byron only)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.H1.A-24	3.3.1-80	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Closed Cycle Cooling Water (Internal) - (Byron only)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.AP-202	3.3.1-45	A
			~~Concrete (External)~~	~~None~~	~~None~~	~~VII.J.AP-282~~	~~3.3.1-112~~	~~A, 4~~
			Concrete (External) - ~~(Byron only)~~	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.C1.AP-198	3.3.1-106	B~~, 5~~
			Condensation (Internal) - (Byron only)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.A-23	3.3.1-89	A
			Diesel Exhaust (Internal) - (Byron only)	Cumulative Fatigue Damage	TLAA			H, 6
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-88	A

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Fuel Oil (Internal) - (Byron only)	Loss of Material	Fuel Oil Chemistry (B.2.1.18)	VII.H1.AP-105	3.3.1-70	A
					One-Time Inspection (B.2.1.20)	VII.H1.AP-105	3.3.1-70	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-127	3.3.1-97	A
					One-Time Inspection (B.2.1.20)	VII.C1.AP-127	3.3.1-97	A
			Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-194	3.3.1-37	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	C
			Soil (External)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.C1.AP-198	3.3.1-106	B
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External) - (Byron only)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.I.AP-284	3.3.1-109x	B
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C1.AP-221	3.3.1-6	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	VII.C1.AP-209	3.3.1-4	~~I, 7~~ ***A,7***
					One-Time Inspection (B.2.1.20)	***VII.C1.AP-209***	***3.3.1-4***	***E, 8***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	Air with Borated Water Leakage (External)	None	None	VII.J.AP-18	3.3.1-120	A
			Closed Cycle Cooling Water (Internal) - (Byron only)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-49	A
			Diesel Exhaust (Internal) - (Byron only)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-128	3.3.1-83	A
				Cumulative Fatigue Damage	TLAA			H, 6
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.H2.AP-104	3.3.1-88	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.20)	VII.C1.AP-138	3.3.1-100	A
			Raw Water (External) - (Byron only)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-40	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-40	A

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VII.I.A-79	3.3.1-9	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-183	3.3.1-38	C
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-281	3.3.1-91	A
		Carbon Steel (with internal coating or lining)	***Air with Borated Water Leakage (External)***	***Loss of Material***	***Boric Acid Corrosion (B.2.1.4)***	***VII.I.A-79***	***3.3.1-9***	***A***
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	***VII.I.A-77***	***3.3.1-78***	***A***
			Waste Water (Internal)	***Loss of Coating Integrity***	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***			***H, 10***
				Loss of Material	***Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)***	***VII.E5.AP-281***	***3.3.1-91***	***A***

Table 3.3.2-22 Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Leakage Boundary	Copper Alloy with less than 15% Zinc	Air with Borated Water Leakage (External)	None	None	VII.J.AP-11	3.3.1-115	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.AP-196	3.3.1-36	A
		Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air with Borated Water Leakage (External)	None	None	VII.J.AP-18	3.3.1-120	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-40	A
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)	VII.E5.AP-278	3.3.1-95	A
	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External) - (Byron only)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VII.I.AP-284	3.3.1-109x	B
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VII.C1.AP-221	3.3.1-6	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	VII.C1.AP-209	3.3.1-4	~~I, 7~~ ***A,7***

Table 3.3.2-22 **Service Water System** **(Continued)**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air with Borated Water Leakage (External)	None	None	VII.J.AP-18	3.3.1-120	A
			Closed Cycle Cooling Water (Internal) - (Byron only)	Loss of Material	Closed Treated Water Systems (B.2.1.12)	VII.C2.A-52	3.3.1-49	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.26)	VII.C1.AP-138	3.3.1-100	A
					One-Time Inspection (B.2.1.20)	VII.C1.AP-138	3.3.1-100	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VII.C1.A-54	3.3.1-40	A

Table 3.3.2-22 **Service Water System** **(Continued)**

Plant Specific Notes: (continued)

4. ***NOT USED*** ~~The Service Water system contains buried piping that is embedded in the reinforced concrete foundation of the Turbine Building Complex. The reinforced concrete foundation, which is founded on the underlying bedrock at the site, provides protection to the below-grade piping. This area, including any potential ground water exposure, is considered oxygen deficient and not conducive to active corrosion. Therefore, no aging affects are assumed for the carbon steel piping embedded in the reinforced concrete foundation of the Turbine Building Complex.~~

5. ***NOT USED*** ~~Byron Station contains carbon steel make-up Service Water piping embedded in a below-grade reinforced concrete box section between the River Screen House and Essential Service Water Cooling Tower. Due to the potential for cracking of the reinforced concrete section that could result in the embedded piping being exposed to rain and groundwater intrusion, loss of material of the carbon steel piping is conservatively assumed applicable. The Buried and Underground Piping (B.2.1.28) program is credited for managing the effects of aging for this buried piping.~~

Table 3.3.2-22 Service Water System (Continued)

Plant Specific Notes: (continued)

~~7. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking is not an applicable aging effect for stainless steel in an Air-Outdoor environment. For more information see LRA Section 3.3.2.2.3.~~

7. Cracking due to stress corrosion cracking is applicable to the piping and valve body components associated with the essential service water cooling tower gear reducer. For more information see LRA Section 3.3.2.2.3.

8. Cracking due to stress corrosion cracking is applicable to the piping, piping components, and piping elements components associated with the essential service water diesel-driven make-up pump exhaust line. For more information see LRA Section 3.3.2.2.3.

9. The aging effects for metallic components with an internal coating or lining in a raw water environment include loss of coating integrity. The Open-Cycle Cooling Water System (B.2.1.11) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a raw water environment.

10. The aging effects for metallic components with an internal coating or lining in a waste water environment include loss of coating integrity. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a waste water environment.

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Section 3.4.2.1.1, Auxiliary Feedwater System, pages 3.4-1 and 3.4-2, is revised as shown below. Additions are indicated with ***bolded italics***.

3.4.2.1.1 Auxiliary Feedwater System

Materials

The materials of construction for the Auxiliary Feedwater System components are:

- Aluminum Alloy
- Carbon Steel
- ***Carbon Steel (with internal lining or coating)***
- Carbon and Low Alloy Steel Bolting
- Copper Alloy with less than 15% Zinc
- Ductile Cast Iron
- Glass
- Gray Cast Iron
- Stainless Steel

Aging Effect Requiring Management

The following aging effects associated with the Auxiliary Feedwater System components require management:

- Cumulative Fatigue Damage
- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

As a result of the response to RAI B.2.1.28-1 provided in Enclosure A of this letter, LRA Section 3.4.2.1.3, Main Condensate and Feedwater System, page 3.4-4, is revised as shown below. Additions are indicated with ***bolded italics***.

3.4.2.1.3 Main Condensate and Feedwater System

Environments

The Main Condensate and Feedwater System components are exposed to the following environments:

- Air - Indoor Uncontrolled
- Air - Outdoor
- Air with Borated Water Leakage
- ***Concrete***
- Lubricating Oil - (Braidwood only)
- Soil
- Treated Water
- Treated Water > 140°F
- Waste Water - (Byron only)

As a result of the response to RAI 2.1.23-1 provided in Enclosure A of this letter, LRA Section 3.4.2.2.2, pages 3.4-8 through 3.4-10, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

3.4.2.2.2 Cracking due to Stress Corrosion Cracking (SCC)

Cracking due to stress corrosion cracking could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. The possibility of cracking also extends to components exposed to air which has recently been introduced into buildings, i.e., components near intake vents. Cracking is only known to occur in environments containing sufficient halides (primarily chlorides) and in which condensation or deliquescence is possible. Condensation or deliquescence should generally be assumed to be possible. Applicable outdoor air environments (and associated indoor air environments) include, but are not limited to, those within approximately 5 miles of a saltwater coastline, those within 1/2 mile of a highway which is treated with salt in the wintertime, those areas in which the soil contains more than trace chlorides, those plants having cooling towers where the water is treated with chlorine or chlorine compounds, and those areas subject to chloride contamination from other agricultural or industrial sources. This item is applicable for the environments described above.

GALL AMP XI.M36, "External Surfaces Monitoring" is an acceptable method to manage the aging effect. The applicant may demonstrate that this item is not applicable by describing the outdoor air environment present at the plant and demonstrating that external chloride stress corrosion cracking is not expected. The GALL Report recommends further evaluation to determine whether an adequate aging management program is used to manage this aging effect based on the environmental conditions applicable to the plant and ASME Code Section XI requirements applicable to the components.

The only stainless steel components exposed to outdoor air in the Steam and Power Conversion system are associated with the condensate storage tank. These components include instrumentation at Byron and Braidwood Stations and drain valves located on the side of each condensate storage tank at Braidwood Station only. These components are evaluated with the Main Condensate and Feedwater System. The drain valves at Braidwood Station are fully insulated, and, therefore, protected from potential halide contamination from environmental sources. Stress corrosion cracking of these components is not expected to occur. The stainless steel instrumentation components associated with the condensate storage tank and exposed to outdoor air at Byron and Braidwood Stations are not insulated. The condensate storage tanks are fabricated from aluminum alloy. There are no stainless steel tanks exposed to an outdoor air environment in the scope of license renewal at Byron and Braidwood Stations (BBS).

The thermal insulation for the condensate storage tank drain valves is enclosed in waterproof jacketing and is not in contact with the stainless steel valves. Therefore, halide contamination of the stainless steel valves due to leaching of contaminants from the insulation is not credible.

A large buildup of halide contamination increases the probability of cracking due to stress corrosion cracking which has the potential to lead to loss of component intended function. As explained below, significant halide contamination of stainless steel piping, piping components, and piping elements exposed to outdoor air or exposed to air which has recently been introduced into buildings is not expected at BBS. Additionally, an elevated temperature increases the likelihood of cracking. Experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steel exposed to an outdoor air environment can crack at temperatures as low as 104°F to 120°F, depending on humidity, component surface temperature, and contaminant concentration and composition. The highest temperatures recorded at BBS over the ten year period between June 1, 2001 and June 1, 2012 were 94.4°F at Byron Station and 98.2°F at Braidwood Station. A review of historical temperature data since construction for areas surrounding BBS indicates that temperatures rarely exceed 100°F. UFSAR Section 2.3.2.1.2 identifies long-term average temperatures of approximately 50°F for BBS. Therefore, stress corrosion cracking of stainless steel piping, piping components, and piping elements exposed to outdoor air or exposed to air which has recently been introduced into buildings is not expected to occur at BBS.

Halide surface contamination is significant in areas where there are greater concentrations of halides such as near the seacoast where salt spray is prevalent or near industrial facilities. Byron and Braidwood Stations are not located near the seacoast. They are located inland, in central Illinois. Both Byron and Braidwood are located in areas where industrial halide concentrations are low, since they are located in rural areas with no heavy industry nearby.

Byron and Braidwood Stations are not located within one half mile of a highway treated with salt in the wintertime. Major highways in the vicinity of Byron Station include interstate I-90 northeast of the site approximately 11 miles away, interstate I-39 east of the site approximately 11 miles away, and interstate I-88 south of the site approximately 14 miles away. The only major highway in the vicinity of Braidwood Station is interstate I-55 northwest of the site approximately three quarters of a mile away.

The cooling towers at Byron Station are treated with sodium hypochlorite. However, chloride contamination ***resulting in the loss of the intended function*** of stainless steel components located outdoors is not expected since the prevailing wind direction is west to east and is directed away from the site. Braidwood Station does not have cooling towers.

Halide contamination of stainless steel components from soil containing more than trace chlorides or from agricultural sources is not expected. However, should halide contamination occur, any potential buildup of halide contamination would be gradual and such contamination would be periodically washed away by rainfall or snow. Cracking due to cumulative build up of halides on stainless steel components located outdoors at BBS has not been experienced and is not expected. The smooth surfaces of the stainless steel components aid the removal of potential halide contamination. Therefore, the concentration of contaminants necessary to initiate stress corrosion cracking of stainless steel is not expected.

Based on the collective environmental conditions, as described above, and confirmed by a review of operating experience, cracking due to stress corrosion cracking of stainless steel components exposed to outdoor air is not expected to occur. ***Regardless, the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program is used to monitor liquid-filled stainless steel components, which are not insulated and are directly exposed to an outdoor air environment, for cracking due to stress corrosion cracking. Components which are insulated are shielded from accumulation of potential contaminants in the environment, and are therefore not susceptible to stress corrosion cracking.*** ~~Therefore, aging management activities for cracking due to stress corrosion cracking for stainless steel components exposed to outdoor air are not required for the period of extended operation.~~

As a result of the responses to RAI's 3.0.3-3 and B.2.1.23-1 provided in Enclosure A of this letter, LRA Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion System, pages 3.4-13 and 3.4-32, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.4.1-2	Stainless steel piping, piping components, and piping elements; tanks exposed to Air – outdoor	Cracking due to stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes, environmental conditions need to be evaluated	***Consistent with NUREG-1801. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage cracking of stainless steel piping, piping components, and piping elements exposed to air-outdoor in the Main Condensate and Feedwater System.*** ~~Based on the evaluation of the environmental conditions at BBS and a review of operating experience, cracking is not an applicable aging effect for the stainless steel bolting, piping, piping components, and piping elements exposed to air - outdoor.~~ See subsection 3.4.2.2.2.

Table 3.4.1 Summary of Aging Management Evaluations for the Steam and Power Conversion System					
Item Number	**Component**	**Aging Effect/ Mechanism**	**Aging Management Programs**	**Further Evaluation Recommended**	**Discussion**
3.4.1-30	Steel, Stainless Steel, Aluminum Tanks ***(within the scope of Chapter XI.M29, "Aboveground Metallic Tanks")*** exposed to Soil or Concrete, ~~Air – outdoor (External)~~ ***or the following external environments air-outdoor, air-indoor uncontrolled, moist air, condensation***	Loss of material due to general ***(steel only)***, pitting, and crevice corrosion***; cracking due to stress corrosion cracking (stainless steel and aluminum only)***	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Consistent with NUREG-1801 with exceptions. The Aboveground Metallic Tanks (B.2.1.17) program will be used to manage loss of material ***and cracking*** of aluminum alloy tanks exposed to air-outdoor in the Main Condensate and Feedwater System. Exceptions apply to the NUREG-1801 recommendations for the Aboveground Metallic Tanks (B.2.1.17) program implementation.
3.4.1-63	***Insulated steel, stainless steel, copper alloy, aluminum, or copper alloy (> 15% Zn) piping, piping components, and tanks exposed to condensation, air-outdoor***	***Loss of material due to general (steel, and copper alloy), pitting, or crevice corrosion, and cracking due to stress corrosion cracking (aluminum, stainless steel and copper alloy (>15% Zn) only)***	***Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" or Chapter XI.M29, "Aboveground Metallic Tanks" (for tanks only)***	***No***	***The External Surfaces Monitoring of Mechanical Components (B.2.1.23) program will be used to manage loss of material of steel, stainless steel, and aluminum insulated piping, piping components, and piping elements exposed to air - outdoor and condensation in the Auxiliary Feedwater System and Main Condensate and Feedwater System.*** ***Based on the evaluation of the environmental conditions and physical configurations at BBS, cracking is not an applicable aging effect for the stainless steel and aluminum insulated piping, piping components, and piping elements exposed to air – outdoor in the Main Condensate and Feedwater System.*** ***See subsection 3.4.2.2.2.***

As a result of the responses to RAI's 3.0.3-2 and 3.0.3-3 provided in Enclosure A of this letter, LRA Table 3.4.2-1, Auxiliary Feedwater System, pages 3.4-34 through 3.4-42 and page 3.4-51, is revised as shown below. Additions are indicated with ***bolded italics***.

Table 3.4.2-1 Auxiliary Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (AFW Cubicle Coolers ***– Braidwood only***) Tube Sheet	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VIII.G.SP-146	3.4.1-19	A
Heat Exchanger - (1A and 2A AFW Cubicle Coolers – Byron only) Tube Sheet	***Pressure Boundary***	***Carbon Steel***	***Raw Water (Internal)***	***Loss of Material***	***Open-Cycle Cooling Water System (B.2.1.11)***	***VIII.G.SP-146***	***3.4.1-19***	***A***
Heat Exchanger - (1B and 2B AFW Cubicle Coolers – Byron only) Tube Sheet	***Pressure Boundary***	***Carbon Steel (with internal coating or lining)***	***Raw Water (Internal)***	***Loss of Coating Integrity***	***Open-Cycle Cooling Water System (B.2.1.11)***			***H, 3***
				Loss of Material	***Open-Cycle Cooling Water System (B.2.1.11)***	***VIII.G.SP-146***	***3.4.1-19***	***A***
Heat Exchanger - (AFW Cubicle Coolers ***– Braidwood only***) Tube Side Components	Pressure Boundary	Carbon Steel	Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VIII.H.S-30	3.4.1-4	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-34	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.11)	VIII.G.SP-146	3.4.1-19	A

Table 3.4.2-1 **Auxiliary Feedwater System** **(Continued)**

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Heat Exchanger - (1A and 2A AFW Cubicle Coolers – Byron only) Tube Side Components	*Pressure Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VIII.H.S-30*	*3.4.1-4*	*A*
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	*VIII.H.S-29*	*3.4.1-34*	*A*
			Raw Water (Internal)	*Loss of Material*	*Open-Cycle Cooling Water System (B.2.1.11)*	*VIII.G.SP-146*	*3.4.1-19*	*A*
Heat Exchanger - (1B and 2B AFW Cubicle Coolers – Byron only) Tube Side Components	*Pressure Boundary*	*Carbon Steel (with internal coating or lining)*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VIII.H.S-30*	*3.4.1-4*	*A*
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	*VIII.H.S-29*	*3.4.1-34*	*A*
			Raw Water (Internal)	*Loss of Coating Integrity*	*Open-Cycle Cooling Water System (B.2.1.11)*			*H, 3*
				Loss of Material	*Open-Cycle Cooling Water System (B.2.1.11)*	*VIII.G.SP-146*	*3.4.1-19*	*A*
Insulated piping, piping components, and piping elements	*Pressure Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VIII.H.S-30*	*3.4.1-4*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VIII.H.S-402*	*3.4.1-63*	*A*
			Raw Water (Internal)	*Loss of Material*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)*	*VIII.G.SP-136*	*3.4.1-38*	*A*

Table 3.4.2-1 Auxiliary Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated Valve Body	*Pressure Boundary*	*Carbon Steel*	*Air with Borated Water Leakage (External)*	*Loss of Material*	*Boric Acid Corrosion (B.2.1.4)*	*VIII.H.S-30*	*3.4.1-4*	*A*
			Condensation (External)	*Loss of Material*	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VIII.H.S-402*	*3.4.1-63*	*A*
			Raw Water (Internal)	*Loss of Material*	*Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25)*	*VIII.G.SP-136*	*3.4.1-38*	*A*

Plant Specific Notes:

3. The aging effects for metallic components with an internal coating or lining in a raw water environment include loss of coating integrity. The Open-Cycle Cooling Water System (B.2.1.11) program is used to manage the identified aging effect applicable to these metallic components with an internal coating or lining in a raw water environment

As a result of the responses to RAI's 3.0.3-3, B.2.1.17-1, B.2.1.23-1, and B.2.1.28-1 provided in Enclosure A of this letter, LRA Table 3.4.2-3, Main Condensate and Feedwater System, pages 3.4-57 through 3.4-63, is revised is revised as shown below. Only those line items affected by the revision are shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

Table 3.4.2-3 Main Condensate and Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.9)	VIII.H.SP-84	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VIII.H.SP-83	3.4.1-10	A
			Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.9)	VIII.H.SP-82	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VIII.H.SP-151	3.4.1-10	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VIII.H.S-40	3.4.1-4	A
					Bolting Integrity (B.2.1.9)	VIII.H.SP-84	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VIII.H.SP-83	3.4.1-10	A
		Stainless Steel Bolting	Air - Outdoor (External)	Loss of Material	Bolting Integrity (B.2.1.9)	VIII.H.SP-82	3.4.1-8	A
				Loss of Preload	Bolting Integrity (B.2.1.9)	VIII.H.SP-151	3.4.1-10	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	VIII.D1.SP-118	3.4.1-2	~~I, 1~~ ***C***
			Soil (External) - (Braidwood Unit 2 only)	Cracking	Buried and Underground Piping (B.2.1.28)			H, 2
				Loss of Material	Buried and Underground Piping (B.2.1.28)	VIII.H.SP-143	3.4.1-48	B
				Loss of Preload	Bolting Integrity (B.2.1.9)	VIII.H.SP-144	3.4.1-6	A

Table 3.4.2-3 Main Condensate and Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Insulated piping, piping components, and piping elements	*Pressure Boundary*	*Aluminum Alloy*	*Air - Outdoor (External)*	*None*	*None*	*VIII.H.S-402*	*3.4.1-63*	*I, 1*
				Loss of Material	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VIII.H.S-402*	*3.4.1-63*	*A*
			Treated Water (Internal)	*Loss of Material*	*One-Time Inspection (B.2.1.20)*	*VIII.D1.SP-90*	*3.4.1-16*	*A*
					Water Chemistry (B.2.1.2)	*VIII.D1.SP-90*	*3.4.1-16*	*A*
		Stainless Steel	*Air - Outdoor (External)*	*None*	*None*	*VIII.H.S-402*	*3.4.1-63*	*I, 1*
				Loss of Material	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VIII.H.S-402*	*3.4.1-63*	*A*
			Treated Water (Internal)	*Loss of Material*	*One-Time Inspection (B.2.1.20)*	*VIII.D1.SP-87*	*3.4.1-16*	*A*
					Water Chemistry (B.2.1.2)	*VIII.D1.SP-87*	*3.4.1-16*	*A*
Insulated Valve Body	*Pressure Boundary*	*Stainless Steel*	*Air - Outdoor (External)*	*None*	*None*	*VIII.H.S-402*	*3.4.1-63*	*I, 1*
				Loss of Material	*External Surfaces Monitoring of Mechanical Components (B.2.1.23)*	*VIII.H.S-402*	*3.4.1-63*	*A*
			Treated Water (Internal)	*Loss of Material*	*One-Time Inspection (B.2.1.20)*	*VIII.D1.SP-87*	*3.4.1-16*	*A*
					Water Chemistry (B.2.1.2)	*VIII.D1.SP-87*	*3.4.1-16*	*A*

Table 3.4.2-3 Main Condensate and Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.SP-147	3.4.1-35	A***, 8***
			Treated Water (External)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-90	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-90	3.4.1-16	A
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-90	3.4.1-16	A
		Carbon Steel	Air - Indoor Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-34	A
			Air with Borated Water Leakage (External)	Loss of Material	Boric Acid Corrosion (B.2.1.4)	VIII.H.S-30	3.4.1-4	A
					External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.H.S-29	3.4.1-34	A
			Concrete (External)	***Loss of Material***	***Buried and Underground Piping (B.2.1.28)***	***VIII.E.SP-145***	***3.4.1-47***	***B***
			Soil (External)	Loss of Material	Buried and Underground Piping (B.2.1.28)	VIII.E.SP-145	3.4.1-47	B
			Treated Water (Internal)	Cumulative Fatigue Damage	TLAA	VIII.D1.S-11	3.4.1-1	A, 4
				Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-74	3.4.1-13	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-74	3.4.1-13	A
				Wall Thinning	Flow-Accelerated Corrosion (B.2.1.8)	VIII.D1.S-16	3.4.1-5	A

Table 3.4.2-3 Main Condensate and Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.23)	VIII.D1.SP-127	3.4.1-3	A
				~~None~~ ***Cracking***	~~None~~ ***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***	VIII.D1.SP-118	3.4.1-2	~~I, 1~~ ***A***
			Soil (External) - (Braidwood Unit 2 only)	Cracking	Buried and Underground Piping (B.2.1.28)			H, 2
				Loss of Material	Buried and Underground Piping (B.2.1.28)	VIII.E.SP-94	3.4.1-49	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-87	3.4.1-16	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D1.SP-88	3.4.1-11	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-88	3.4.1-11	A
				Cumulative Fatigue Damage	TLAA	VII.E3.A-62	3.3.1-2	A, 4
				Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-87	3.4.1-16	A

Table 3.4.2-3 Main Condensate and Feedwater System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Condensate Storage Tanks)	Pressure Boundary	Aluminum Alloy	Air - Outdoor (External)	Loss of Material	Aboveground Metallic Tanks (B.2.1.17)	VIII.E.SP-140	3.4.1-30	B
				Cracking	***Aboveground Metallic Tanks (B.2.1.17)***	***VIII.E.SP-140***	***3.4.1-30***	***B***
			Soil (External)	Loss of Material	Aboveground Metallic Tanks (B.2.1.17)	VIII.E.SP-139	3.4.1-31	B
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-90	3.4.1-16	C
					Water Chemistry (B.2.1.2)	VIII.D1.SP-90	3.4.1-16	C
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			~~Air - Outdoor (External)~~	~~Loss of Material~~	~~External Surfaces Monitoring of Mechanical Components (B.2.1.23)~~	~~VIII.D1.SP-127~~	~~3.4.1-3~~	~~A~~
				~~None~~	~~None~~	~~VIII.D1.SP-118~~	~~3.4.1-2~~	~~I, 1~~
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-87	3.4.1-16	A
			Treated Water > 140 F (Internal)	Cracking	One-Time Inspection (B.2.1.20)	VIII.D1.SP-88	3.4.1-11	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-88	3.4.1-11	A
				Loss of Material	One-Time Inspection (B.2.1.20)	VIII.D1.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.D1.SP-87	3.4.1-16	A

Table 3.4.2-3 Main Condensate and Feedwater System (Continued)

Plant Specific Notes:

1. Based on an evaluation of the environmental conditions at BBS and a review of operating experience, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for ***insulated*** stainless steel ***and aluminum*** in an Air-Outdoor environment. ***Per NACE SP0198-2010, SCC can occur under insulation when the evaporation of water, due to contact with hot stainless steel, causes the concentration of halides on the surface of stainless steel components. The potential sources of halide contamination are leachable halides from insulating materials and/or external environmental sources. The insulating materials for this component do not contain leachable halides. External sources of halides are not a significant contributor to the occurrence of SCC as the insulation shelters the component external surface. In addition, since this is not hot piping, the concentration of halides is not expected to occur. Therefore, cracking due to stress corrosion cracking (SCC) is not an applicable aging effect for insulated stainless steel and aluminum in an Air-Outdoor environment. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program will be used to manage loss of material of this component.*** For more information see LRA Section 3.4.2.2.2.

8. Uninsulated aluminum alloy piping is contained within the normally accessible condensate storage tank valve vaults, associated with the pipe penetration from the tank bottom through the concrete vault ceiling and terminating at a flange connection to carbon steel piping inside the vault. Piping and components contained with these valve vaults have been assigned the Air-Outdoor environment. Since the aluminum alloy piping is sheltered inside the valve vault, and at the upper elevation directly underneath the tank bottom, cracking due to halide contamination from the outside air environment is not considered an applicable aging effect.

As a result of the responses to RAI's 3.0.3-1 and 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.11, pages A-17 and A-18, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.11 Open-Cycle Cooling Water System

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing preventive, mitigative, condition monitoring, and performance monitoring program based on the implementation of NRC GL 89-13, which includes (a) surveillance and control of bio-fouling, (b) tests to verify heat transfer, (c) routine inspection and maintenance program, (d) system walkdown inspection, and (e) review of maintenance, operating, and training practices and procedures. The Open-Cycle Cooling Water System program applies to components constructed of various materials, including steel, stainless steel, gray cast iron, copper alloys, nickel alloys, titanium, and polymeric materials.

The Open-Cycle Cooling Water System (OCCWS) aging management program manages heat exchangers, piping, piping elements, and piping components in safety-related and nonsafety-related raw water systems that are exposed to a raw water environment for loss of material***, loss of coating integrity,*** and reduction of heat transfer. The guidelines of NRC Generic Letter 89-13 are implemented through the site GL 89-13 activities for heat exchangers and the Raw Water Corrosion program for piping segments. System and component testing, visual inspections, non-destructive examination (NDE) (i.e., ultrasonic testing and eddy current testing), and chemical injection are conducted to ensure that identified aging effects are managed such that system and component intended functions and integrity are maintained.

The OCCWS aging management program includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13. Periodic heat transfer testing, visual inspection, and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the sites' commitments to GL 89-13 to verify heat transfer capabilities. Additionally, safety-related piping segments are NDE tested periodically to ensure that there is no significant loss of material, which could cause a loss of intended function.

Safety-related and nonsafety-related piping inspections are performed using a 100% scan ultrasonic testing method, where possible, to ensure that localized corrosion indicative of microbiologically influenced corrosion (MIC) is detected. The inspections required by this program are performed at locations that are chosen to be leading indicators of the material condition of the internal surface of components within the scope of the program. The specific locations for inspections are chosen based on commitments made in the Byron and Braidwood responses to NRC GL 89-13, piping configuration, flow conditions (e.g., stagnant or low flow areas), and operating history (e.g., prior inspection results). The maximum interval for re-inspection is based on the calculated remaining life of the component. If required, piping replacement is performed prior to the development of through-wall leakage.

In addition, the internal coatings of components within the scope of this program are periodically visually inspected to ensure that loss of coating

integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.

Nonsafety-related piping segments which have the potential for spatial interactions with safety-related equipment will be NDE tested periodically as delineated in the enhancement described below.

The Open-Cycle Cooling Water System aging management program will be enhanced to:

1. Perform periodic volumetric inspections for loss of material in the non-essential service water system piping at a minimum of two (2) locations on each unit in both the auxiliary building and the turbine building for a total of four (4) periodic inspections per unit every refueling cycle.

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

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.16, page A-21, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.16 Fire Water System

The Fire Water System aging management program is an existing condition monitoring program that provides for system pressure monitoring, system header flushing, buried ring header flow testing, pump performance testing, hydrant full flow flushing and full flow verification, sprinkler and deluge system flushing and flow testing, hydrostatic testing, and inspection activities. Major component types managed by this program include sprinklers, fittings, valves, hydrants, hose stations, standpipes, tanks, pumps, and aboveground and buried piping and components. There are no underground (i.e., below grade but contained within a tunnel or vault) piping and components within the scope of the Fire Water System aging management program.

Opportunistic visual inspections, performed when the internal surface of the system is made accessible due to normal plant maintenance activities, and existing volumetric non-destructive examinations will be credited to ensure age related degradation is identified prior to loss of system intended function.

Buried ring header flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner.

System functional tests, flow tests, flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. These activities are performed periodically to ensure that the loss of material due to corrosion aging effect is managed such that the system and component intended functions are maintained.

In addition, the internal coatings of components within the scope of this program are periodically visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.

The Fire Water System aging management program will be enhanced to:

1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2002 Edition), Section 5.3.1.1.1. This testing will be performed at the 50-year in-service date and every 10 years thereafter.

2. Provide for chemical addition, accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion (Byron only).

These enhancements will be implemented prior to the period of extended operation, with the testing and inspections performed in accordance with the schedule described above.

As a result of the responses to RAI's B.2.1.17-1 and B.2.1.17-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.17, page A-22, is revised as shown below. Changes are highlighted with ***bolded italics*** for inserted text and ~~strikethroughs~~ for deleted text.

A.2.1.17 Aboveground Metallic Tanks

The Aboveground Metallic Tanks program is a new condition monitoring program which manages loss of material ***and cracking*** on the external surfaces of aboveground metallic tanks within the scope of license renewal. The program applies only to aluminum condensate storage tanks which are supported on concrete and a four inch sand cushion above compacted backfill. ***There are no indoor tanks within the scope of this program. The condensate storage tanks are cathodically protected.*** The original plant design specifications do not require the aluminum condensate storage tanks to be coated or painted on the external surface as a preventive measure to mitigate corrosion. This is due to the corrosion resistance properties of aluminum. This program includes preventive measures to mitigate corrosion by protecting the external surfaces of metallic components, per standard industry practice, with sealant at the concrete-component interface.

The program requires periodic visual inspections ***once per eighteen (18) month operating cycle*** for degradation of the external surface of the ***insulation*** lagging, flashing, ~~insulation~~ ***caulking***, roof~~ing~~, and accessible sealant ***(sealant inspections are supplemented with physical manipulation)***. The program also requires periodic visual inspections ***and liquid penetrant examinations*** of the tank external surfaces ***at 25 locations for both tanks combined per site*** and includes, on a sampling basis, removal of selected tank lagging and insulation to permit inspections of the external tank surfaces and exposed sealants. ***The tank external surface inspections and examinations will be performed each 10-year period starting 10 years prior to the period of extended operation. The sample locations will include at least four locations below penetrations through the insulation and its jacketing (e.g. instrument nozzles, tank heaters, ladder). The remaining sample locations will be distributed such that inspections will occur on the tank dome, sides, and near the bottom.***

~~Program effectiveness is determined by measuring the thickness of the tank bottoms to ensure that significant age-related degradation is not occurring and that the component's intended function is maintained during the period of extended operation.~~

~~This new aging management program will be implemented prior to the period of extended operation.~~ ***One-time tank bottom ultrasonic inspections (one CST per station) will be performed within the 5-year period prior to the period of extended operation. The cathodic protection availability and effectiveness criteria in LR-ISG-2011-03 Table 4c, notes 3.ii and 3.iii, respectively, will be required to be met commencing 5 years prior to the PEO and during the PEO. The One-Time Inspection (B.2.1.20) aging management program supplements this program by providing for a one-time visual inspection of the internal surface of the CSTs to verify the effectiveness of the Water Chemistry (B.2.1.2) aging management program.*** ~~Tank bottom UT inspections will be performed within the five (5) year period prior to the period of extended operation, between years five (5) and 10 of the period of extended operation, and whenever a tank is drained.~~

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.18, pages A-22 and A-23, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.18 Fuel Oil Chemistry

The Fuel Oil Chemistry program is an existing mitigative and condition monitoring program that manages loss of material***, loss of coating integrity,*** and reduction in heat transfer in piping, piping elements, piping components, tanks, and heat exchangers. The Fuel Oil Chemistry aging management program relies on a combination of surveillance procedures and maintenance activities being implemented to provide assurance that contaminants are monitored and controlled in fuel oil for systems and components within the scope of license renewal. The program requires fuel oil parameters to be maintained at acceptable levels in accordance with Technical Specifications, Technical Requirement Manual, and ASTM Standards (ASTM D 0975-98/-06b, D 2709-96e, D 4057-95, and D 5452-98). Fuel oil sampling and analysis is performed in accordance with approved procedures for new and stored fuel oil. Fuel oil tanks are periodically drained of accumulated water, cleaned, and internally inspected to minimize exposure to fuel oil contaminants. ***During these inspections, the internal coatings of the tanks are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.*** These activities effectively manage the effects of aging by maintaining contaminants at acceptably low concentrations.

As a result of the response to RAI B.2.1.23-1 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.20, pages A-25 and A-26, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.20 One-Time Inspection

The One-Time Inspection aging management program is a new condition monitoring program that will be used to verify the system-wide effectiveness of the Water Chemistry (A.2.1.2) program, Fuel Oil Chemistry (A.2.1.18) program, and Lubricating Oil Analysis (A.2.1.26) program which are designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation. The program manages loss of material, cracking, and reduction of heat transfer in piping, piping components, piping elements, tanks, pump casings, heat exchangers, and other components within the scope of license renewal. The program identifies inspections focused on locations that are isolated from the flow stream, that are stagnant, or that have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. A representative sample size of 20 percent of the population (up to a maximum of 25 component inspections) will be established for each of the sample groups and will focus on the bounding or lead components most susceptible to aging due to time in service and severity of operating conditions. The program verifies either no unacceptable age-related degradation is occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the period of extended operation.

The One-Time Inspection aging management program will also be utilized, in specific cases where existing data is insufficient:

a) to validate that a particular aging effect is not occurring, or
b) to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation.

In these cases, the components will not require additional aging management.

The elements of the program include (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and plant-specific and industry operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could adversely impact an intended function before the end of the period of extended operation.

This program is not used for systems or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections will be used in these cases.

The One-Time Inspection program will be implemented prior to the period of extended operation. The one-time inspections will be performed within the 10 year period prior to the period of extended operation.

As a result of the responses to RAI's B.3.0.3-3 and B.2.1.23-1 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.23, page A-28, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.23 External Surfaces Monitoring of Mechanical Components

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspections of metallic and elastomeric components such as piping, piping components, ducting, elastomeric components, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric components through visual inspection of external surfaces for evidence of loss of material ***and cracking***. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers.

Periodic representative inspections to detect corrosion (i.e. loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic inspections under insulation to detect corrosion under insulation will continue.

The external surfaces of components that are buried are inspected via the Buried and Underground Piping (A.2.1.28) program. The external surfaces of above ground tanks are inspected via the Aboveground Metallic Tanks (A.2.1.17) program. Internal surfaces are inspected via the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (A.2.1.25) program.

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

As a result of the responses to RAI's 3.0.3-2 and B.2.1.25-1 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.25, page A-29, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that directs visual inspections of internal surfaces of components within the scope of license renewal be performed when they are made accessible during periodic system and component surveillances or during the performance of maintenance activities. The program provides assurance that existing environmental conditions are not causing material degradation that could result in loss of intended function.

This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement.

The program consists of visual inspections of the internal surfaces of metallic components such as piping, piping elements and piping components, ducting components, tanks, heat exchangers, and other components that are exposed to air-indoor uncontrolled, diesel exhaust, condensation, and any water system other than open-cycle cooling water system, closed treated water system, and fire water system. ***During these inspections, the internal coatings of components are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.*** The program also consists of visual inspections of the internal surfaces of elastomeric components that are exposed to condensation, treated water, fuel oil, and lubricating oil augmented by physical manipulation or pressurization to detect hardening or loss of strength where appropriate. The program will manage the aging effects of loss of material, reduction of heat transfer, and cracking for metallic components. The program will also manage the aging effects of loss of material and hardening and loss of strength for elastomeric components. ***The program will also manage the aging effect of loss of coating integrity for metallic components with internal linings or coatings.*** The program includes provisions for visual inspections of the internal surfaces of components not managed under other aging management programs.

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

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.26, page A-29, is revised as shown below. Additions are indicated with ***bolded italics***.

A.2.1.26 Lubricating Oil Analysis

The Lubricating Oil Analysis aging management program is an existing preventive and mitigative program that ensures that the oil environment in the mechanical systems is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of this program. The Lubricating Oil Analysis program ensures that oil systems are maintained free of contaminants (primarily water and particulates), thereby, preserving an environment that is not conducive to loss of material or reduction of heat transfer in piping, piping components, piping elements, valve bodies, pump casings, gear boxes, tanks, and heat exchangers exposed to an oil environment. Testing activities include sampling and analysis of lubricating oil for detrimental contaminants. The presence of oil contaminants (e.g., water or particulates) may also indicate in-leakage and corrosion product buildup. ***Loss of coating integrity for coated or lined components within the scope of this program will be detected by the presence of particulates in the oil.***

As a result of the responses to RAI's B.2.1.28-3 and B.2.1.28-4 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.28, page A-31 is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

A.2.1.28 Buried and Underground Piping

The Buried and Underground Piping aging management program will be enhanced to:

7. Inspection quantities of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10 year period, beginning 10 years prior to the period of extended operation.
    a. The piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications (Byron only).

9. In performing cathodic protection surveys, only the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness~~, unless the -100mV polarization criteria can be demonstrated effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured~~. ***Alternatively, soil corrosion, or electric resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys.*** An upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings.

As a result of the responses to RAI's 3.0.3-1 and 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.11, pages B-82 and B-83, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

B.2.1.11 Open-Cycle Cooling Water System

Program Description

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing preventive, mitigative, condition monitoring, and performance monitoring program that manages heat exchangers, piping, piping elements, and piping components in safety-related and nonsafety-related raw water systems that are exposed to a raw water environment for loss of material***, loss of coating integrity,*** and reduction of heat transfer. The activities for this program are consistent with the site commitments to the requirements of GL 89-13 and provide for management of aging effects in raw water cooling systems through tests, inspections, and component cleaning. System and component testing, visual inspections, non-destructive examination (NDE) (i.e., ultrasonic testing and eddy current testing), and biocide and chemical treatment are conducted to ensure that identified aging effects are managed such that system and component intended functions are maintained.

The OCCWS includes those systems that transfer heat from safety-related systems, structures, and components to the ultimate heat sink as defined in GL 89-13 as well as those raw water systems which are in scope for license renewal for potential spatial interaction but have no safety-related heat transfer function.

The guidelines of GL 89-13 are utilized for the surveillance and control of bio-fouling for the OCCWS aging management program. Procedures provide instructions and controls for chemical and biocide injection. Periodic inspections are performed for the presence of asiatic clams, bryozoa (Braidwood only), and mollusks and biocide treatments are applied as necessary.

Periodic heat transfer testing, visual inspection and cleaning of safety-related heat exchangers with a heat transfer intended function is performed in accordance with the site commitments to GL 89-13 to verify heat transfer capabilities. Additionally, safety-related piping segments are tested periodically to ensure that there is no significant loss of material, which could cause a loss of intended function. Nonsafety-related piping segments have potential for spatial interactions with safety-related equipment, and will be NDE tested periodically as delineated in the enhancement described below.

Safety-related and nonsafety-related piping inspections are performed using a 100% scan ultrasonic testing method, where possible, to ensure that localized corrosion indicative of microbiologically influenced corrosion (MIC) is detected. The inspections required by this program are performed at locations that are chosen to be leading indicators of the material condition of the internal surface of components within the scope of the program. The specific locations for inspections are chosen based on commitments made in the Byron and Braidwood responses to NRC GL 89-13, piping configuration, flow conditions (e.g., stagnant or low flow areas), and operating history (e.g., prior inspection results). The maximum interval for re-inspection is based on the calculated

remaining life of the component. If required, piping replacement is performed prior to the development of through-wall leakage.

Routine inspections and maintenance ensure that corrosion, erosion, sediment deposition (silting), scaling (Braidwood only), and bio-fouling do not degrade the performance of safety-related systems serviced by OCCWS aging management program.

No credit is taken for protective coatings on safety-related components in the OCCWS aging management program in determining potential aging effects. However, this program is used to assure the lining/coating integrity. ***At Byron and Braidwood,*** ~~P~~***p***rotective coatings ***are utilized*** on selected ***safety-related and nonsafety-related*** heat exchangers ~~(i.e., control room refrigeration unit condensers, and emergency diesel generator jacket water coolers, on the endbells, channel heads, cover plates, and tubesheets)~~ ***within the scope of this program and*** are periodically inspected and repaired, as necessary. ***Periodic visual inspections of the internal coatings of components within the scope of this program are performed every one to six years, depending on the heat exchanger. The visual inspections ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.***

~~Additionally, at Byron only, there are coatings on the reactor containment fan cooler channel heads and the essential service water makeup pump jacket water and gear oil coolers.~~

The Buried and Underground Piping (B.2.1.28) aging management program activities are adequate for managing the aging effects of external surfaces of buried and underground piping and components. The external surface of the aboveground raw water piping and heat exchangers is managed by the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program. However, the internal and external surfaces of the piping exposed to raw water in the Essential Service Water Cooling Tower (Byron only) will be managed by the Open-Cycle Cooling Water System program.

Examination of polymeric materials in systems serviced by the Open-Cycle Cooling Water System program will be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.25) aging management program.

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.16, pages B-109 and B-110, is revised as shown below. Additions are indicated with ***bolded italics***.

B.2.1.16 Fire Water System

Program Description

The Fire Water System aging management program is an existing condition monitoring program that manages the loss of material aging effect for the water-based fire protection system and associated components, through the use of system pressure monitoring, system header flushing, buried ring header flow testing, pump performance testing, hydrant full flow flushing and full flow verification, sprinkler and deluge system flushing and flow testing, hydrostatic testing, and inspection activities. ***In addition, the Fire Water System aging management program manages the loss of coating integrity aging effect for the components with internal coatings within the scope of the program.***

The program applies to water-based fire protection systems that consist of sprinklers, fittings, valves, hydrants, hose stations, standpipes, tanks, pumps, and aboveground and buried piping and components. The program manages aging of fire protection components exposed to outdoor air and raw water. There are no underground (i.e., below grade but contained within a tunnel or vault) piping and components within the scope of the Fire Water System aging management program at Byron and Braidwood Stations. Aging of the external surfaces of buried fire main piping is managed as described in the Buried and Underground Piping (B.2.1.28) aging management program.

The fire water system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated. The program ensures that testing and inspection activities are performed and the results are documented and reviewed by the Fire Protection system manager for analysis and trending. These monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation.

Opportunistic visual inspections, performed when the internal surface is made accessible due to normal plant maintenance activities, and existing volumetric non-destructive examinations of piping will be credited to ensure age related degradation is identified prior to loss of system intended function. Selected portions of the fire protection system piping located aboveground and exposed to water will be inspected by non-intrusive volumetric examinations, to ensure that aging effects are managed and that pipe wall thickness is within acceptable limits. Pipe wall thickness inspections will be performed before the end of the current operating term and continued at a frequency of at least once every 3 years during the period of extended operation. These inspections will be capable of evaluating (1) pipe wall thickness to ensure against loss of system intended function and (2) the inner diameter of the piping as it applies to the flow requirements of the fire protection system.

In addition, periodic visual inspections of components with internal coatings are performed. The visual inspections ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.

Buried ring header flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner.

50-year sprinkler head testing will be conducted using the guidance provided in NFPA 25. Performance of the initial 50-year tests will be determined based on the date of the sprinkler system installation. Subsequent inspections will be performed every 10 years after the initial 50-year testing.

At Byron only, as a result of operating experience, an enhancement to allow for chemical addition, accompanied with system flushing to allow for adequate dispersal of the chemicals throughout the system, to prevent or minimize microbiologically induced corrosion has been included in the Fire Water System aging management program.

System functional tests, flow tests, flushes, and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. These activities are performed periodically to ensure that the loss of material due to corrosion aging effect is managed such that the system and component intended functions are maintained.

As a result of the responses to RAIs B.2.1.17-1 and B.2.1.17-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.17, pages B-115 and B-116, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

B.2.1.17 Aboveground Metallic Tanks

Program Description

The Aboveground Metallic Tanks program is a new condition monitoring program which manages loss of material ***and cracking*** on the external surfaces of aboveground metallic tanks that are supported on concrete and a four inch sand cushion above compacted backfill in soil and outdoor air environments by performing visual inspections on those tanks within the scope of license renewal. The program only applies to the aluminum condensate storage tanks. ***There are no indoor tanks within the scope of this program. The condensate storage tanks are cathodically protected.*** At Byron and Braidwood Stations the aluminum condensate storage tanks are protected by lagging, roof flashing, and insulation, and are not coated with a protective paint or coating on the external surface. At Byron there is sealant at the base of the lagging and Braidwood has sealant at the base of the tank. The original plant design specifications do not require the aluminum condensate storage tanks to be coated or painted on the external surface as a preventive measure to mitigate corrosion. This is due to the corrosion resistance properties of aluminum. This program includes preventive measures to mitigate corrosion by protecting the external surfaces of metallic components, per standard industry practice, with sealant at the concrete-component interface. Lagging with overlapping seams jacket the insulation to mitigate moisture intrusion and serve as a corrosion preventive measure.

Once per eighteen (18) month operating cycle, the program requires periodic visual inspections for degradation of the external surface of the ***insulation*** lagging, flashing, ~~insulation~~ ***caulking***, roof~~ing~~, and accessible sealant. ***At Braidwood only, inspection of the sealant at the base of the tanks requires the removal of selected tank lagging and insulation. At Byron, the sealant is at the concrete-lagging interface. These sealant visual inspections will be augmented by physical manipulation to detect hardening and loss of strength.*** The program also requires periodic visual inspections ***and liquid penetrant examinations*** of the tank external surfaces ***at 25 locations for both tanks combined per site*** and includes, on a sampling basis, removal of selected tank lagging and insulation to permit inspections of the external tank surfaces and exposed sealants. ***The tank external surface inspections and examinations will be performed each 10-year period starting 10 years prior to the period of extended operation. The sample locations will include at least four locations below penetrations through the insulation and its jacketing (e.g. instrument nozzles, tank heaters, ladder). The remaining sample locations will be distributed such that inspections will occur on the tank dome, sides, and near the bottom.*** ~~At Braidwood only, inspection of the sealant at the base of the tanks requires the removal of selected tank lagging and insulation. At Byron, the sealant is at the concrete-lagging interface. These sealant visual inspections will be augmented by physical manipulation to detect hardening and loss of strength.~~

~~Program effectiveness is determined by measuring the thickness of the tank bottoms to ensure that significant age-related degradation is not occurring and that the~~

~~component's intended function is maintained during the period of extended operation.~~ ***One-time tank bottom ultrasonic inspections (one CST per station) will be performed within the 5-year period prior to the period of extended operation. The cathodic protection availability and effectiveness criteria of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program XI.M41, 'Buried and Underground Piping and Tanks'," are included in the notes of Table 4c of the ISG. The cathodic protection availability and effectiveness criteria in Table 4c, notes 3.ii and 3.iii, respectively, will be required to be met commencing 5 years prior to the PEO and during the PEO.*** ~~Tank bottom UT inspections will be performed within five (5) years prior to entering the period of extended operation, between years five (5) and 10 of the period of extended operation, and whenever a tank is drained~~ ***The one-time tank bottom ultrasonic inspections will*** ~~to ascertain whether~~ ***confirm that*** there ~~is~~ ***has not been*** significant loss of material at the tank bottom during normal operation. ~~If no tank bottom plate loss of material is identified after the first two inspections, subsequent inspections will be performed whenever the tank is drained during the period of extended operation.~~ If any age-related degradation of the tank bottom plate is found, further evaluations will be performed as part of the corrective action program. ***The One-Time Inspection (B.2.1.20) aging management program supplements this program by providing for a one-time visual inspection of the internal surface of the CSTs to verify the effectiveness of the Water Chemistry (B.2.1.2) aging management program.***

The monitoring methods required by this aging management program will be effective in detecting the loss of material aging effect and the frequency of monitoring will be adequate to prevent significant age-related degradation. The Aboveground Metallic Tanks program is a new program that will be implemented prior to the period of extended operation.

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.18, page B-121, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

B.2.1.18 Fuel Oil Chemistry

Program Description

The Fuel Oil Chemistry program is an existing mitigative and condition monitoring program that manages loss of material***, loss of coating integrity,*** and reduction in heat transfer in piping, piping elements, piping components, tanks, and heat exchangers in a fuel oil environment. The Fuel Oil Chemistry aging management program relies on a combination of surveillance procedures and maintenance activities being implemented to provide assurance that contaminants are monitored and controlled in fuel oil for systems and components within the scope of license renewal. The program requires fuel oil parameters to be maintained at acceptable levels in accordance with Technical Specifications, Technical Requirement Manual, and ASTM Standards (ASTM D 0975-98/-06b, D 2709-96e, D 4057-95, and D 5452-98). Fuel oil sampling and analysis is performed in accordance with approved procedures for new and stored fuel oil. Monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation. Fuel oil tanks are periodically drained of accumulated water, cleaned, and internally inspected to minimize exposure to fuel oil contaminants. ~~Protective coatings are not credited for mitigating the loss of material due to general, pitting, and crevice corrosion, microbiologically influenced corrosion (MIC), and biological fouling in fuel tanks.~~ ***During these inspections, the internal coatings of the tanks are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.*** These activities effectively manage the effects of aging by maintaining contaminants at acceptably low concentrations.

As a result of the response to RAI B.2.1.23-1 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.20, pages B-132 through B-133, is revised as shown below. Additions are indicated with ***bolded italics***.

B.2.1.20 One-Time Inspection

Program Description

The One-Time Inspection aging management program is a new condition monitoring program that will be used to verify the system-wide effectiveness of the Water Chemistry (B.2.1.2), Fuel Oil Chemistry (B.2.1.18), and Lubricating Oil Analysis (B.2.1.26) aging management programs which are designed to prevent or minimize age-related degradation so that there will not be a loss of intended function during the period of extended operation. The program manages loss of material, cracking, and reduction of heat transfer in piping, piping components, piping elements, tanks, pump casings, heat exchangers, and other components within the scope of license renewal for ***air-outdoor,*** fuel oil, lubricating oil, reactor coolant, steam, treated water, and treated borated water environments. The program identifies inspections focused on locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. A representative sample size of 20 percent of the population (up to a maximum of 25 component inspections) will be established for each of the sample groups and will focus on the bounding or lead components most susceptible to aging due to time in service, and severity of operating conditions. The program verifies either no unacceptable age-related degradation is occurring or triggers additional actions that will assure the intended function of affected components will be maintained during the period of extended operation. Technical justification of the methodology and sample size used for selecting components for one-time inspection is documented in the One-Time Inspection Sample Basis Document.

The One-Time Inspection aging management program will also be utilized, in specific cases where existing data is insufficient:

- ***a) to validate that a particular aging effect is not occurring, or***
- ***b) to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation.***

In these cases, the components will not require additional aging management.

The elements of the program include (a) determination of the sample size of components to be inspected based on an assessment of materials of fabrication, environment, plausible aging effects, and plant-specific and industry operating experience, (b) identification of the inspection locations in the system or component based on the potential for the aging effect to occur, (c) determination of the examination technique, including acceptance criteria that would be effective in managing the aging effect for which the component is examined, and (d) an evaluation of the need for follow-up examinations to monitor the progression of aging if age-related degradation is found that could adversely impact an intended function before the end of the period of extended operation. The monitoring methods will be effective in detecting the applicable aging effects and the frequency of monitoring will be adequate to prevent significant age-related degradation.

This program is not used for systems or components with known age-related degradation or when the environment in the period of extended operation is not expected to be equivalent to that in the prior 40 years. Periodic inspections will be used in these cases.

The One-Time Inspection program will be implemented prior to the period of extended operation. The one-time inspections will be performed within the 10 year period prior to the period of extended operation.

As a result of the responses to RAI's 3.0.3-3 and B.2.1.23-1 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.23, pages B-147 and B-148, is revised as shown below. Additions are indicated with ***bolded italics***.

B.2.1.23 External Surfaces Monitoring of Mechanical Components

Program Description

The External Surfaces Monitoring of Mechanical Components aging management program is a new condition monitoring program that directs visual inspections of external surfaces of components be performed during system inspections and walkdowns. The program consists of periodic visual inspection of metallic and elastomeric components such as piping, piping components, ducting, elastomeric components, and other components within the scope of license renewal. The program manages aging effects of metallic and elastomeric components through visual inspection of external surfaces for evidence of loss of material ***and cracking*** in air-indoor, air-outdoor, and air with borated water leakage environments. Visual inspections are augmented by physical manipulation as necessary for evidence of hardening and loss of strength.

Periodic representative inspections to detect corrosion (i.e. loss of material) under insulation will be conducted on in-scope indoor insulated components and tanks, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation.

For a representative sample of in-scope outdoor components (with the exception of the condensate storage tanks) and for any indoor components operated below the dew point (except indoor insulated tanks, which are discussed below), remove the insulation and inspect a minimum of 20 percent of the in-scope piping length for each material type, 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 should be conducted in each environment (e.g., air-outdoor, condensation) where condensation or moisture on the surfaces of the component could occur routinely or seasonally.

For a representative sample of in-scope insulated indoor tanks operated below the dew point, the insulation will be removed from either 25 1-square-foot sections or 20 percent of the surface area and inspect the exterior surface of the tank. Sample inspection points will be distributed such that inspections occur on the tank domes, sides, near the bottoms, at points where structural supports or instrument nozzles penetrate the insulation, and where water collects (such as on top of stiffening rings).

Inspections subsequent to the initial inspection will consist of examination of

the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic inspections under insulation to detect corrosion under insulation will continue.

Removal of tightly-adhering insulation that is impermeable to moisture will not be 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 and, therefore, will not be removed. The entire accessible population (i.e., 100%) of in-scope piping that has tightly-adhering insulation will be visually inspected for damage to the moisture barrier during each 10-year period of the period of extended operation. Tightly-adhering insulation will be considered to be a separate population from the remainder of insulation installed on in-scope components. These inspections will not be credited towards the inspection quantities for other types of insulation as described above.

Materials of construction inspected under this program include aluminum alloy, carbon steel, copper alloy, ductile cast iron, galvanized steel, gray cast iron, low alloy steel, and stainless steel. Examples of components this program inspects are piping and piping components, ducting, heat exchangers, tanks, pumps, expansion joints, and hoses. The inspection parameters for metallic components include material condition, which consists of evidence of rust, general, pitting and crevice corrosion, discoloration and coating degradation; evidence of insulation damage or wetting; leakage from piping, ducting, or component bolted joints***; and leakage for detection of cracks on the external surfaces of stainless steel and aluminum components exposed to an air environment containing halides***. Coating degradation is used as an indicator of possible underlying degradation of the component. Inspection parameters for elastomeric components include hardening, discoloration, surface cracking, crazing, scuffing, exposure of internal reinforcement for reinforced elastomers, and dimensional changes.

The External Surfaces Monitoring of Mechanical Components program is a visual condition monitoring program that does not include preventive or mitigative actions. The monitoring methods are effective in detecting the loss of material, ***cracking,*** and hardening and loss of strength aging effects and the once per refueling cycle frequency of monitoring is adequate to prevent significant age-related degradation.

Inspections***, with the exception of inspections performed to detect corrosion under insulation,*** are performed at a frequency not to exceed once per refueling cycle. This frequency accommodates inspections of components that may be in locations that are normally only accessible during refueling outages. Surfaces that are not readily visible during plant operations and refueling outages are inspected when they are made accessible and at such intervals that would ensure the components intended functions are maintained. ***Inspections performed to detect corrosion under insulation will be conducted during each 10-year period of the period of extended operation.***

Any visible evidence of degradation will be evaluated for acceptability of continued service. Acceptance criteria will be based upon component, material, and environment combinations. Deficiencies will be documented and evaluated under the corrective action program.

The external surfaces of components that are buried are inspected via the Buried and Underground Piping (B.2.1.28) program. The external surfaces of above ground tanks are inspected via the Aboveground Metallic Tanks (B.2.1.17) program. This program does not provide for managing aging of internal surfaces. The External Surfaces Monitoring of Mechanical Components program is a new program that will be implemented prior to the period of extended operation.

As a result of the responses to RAI's 3.0.3-2 and B.2.1.25-1 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.25, page B-156 is revised as shown below. Additions are indicated with ***bolded italics***.

B.2.1.25 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Program Description

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that manages the aging of the internal surfaces of piping, piping elements and piping components, ducting components, tanks, heat exchangers, and other components. This program will manage the aging effects of loss of material, reduction of heat transfer, and cracking for metallic components that are exposed to air - indoor uncontrolled, diesel exhaust, condensation, raw water, treated water, and waste water environments. This program will also manage the aging effects of loss of material and hardening and loss of strength for elastomeric components that are exposed to condensation, fuel oil, lubricating oil, and treated water environments. ***The program will also manage the aging effect of loss of coating integrity for metallic components with internal linings or coatings.*** The program includes provisions for visual inspections of the internal surfaces of components not managed under other aging management programs, augmented by physical manipulation or pressurization to detect hardening or loss of strength of elastomers where appropriate. ***During these inspections, the internal coatings of components are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage.*** Inspections will be performed when the internal surfaces are made accessible during the performance of periodic surveillances, maintenance activities, and scheduled outages.

This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement.

Identified deficiencies due to age-related degradation are documented and evaluated under the corrective action program. Acceptance criteria are established in the maintenance and surveillance procedures or are established during engineering evaluation of the degraded condition. If the inspection results are not acceptable, the condition is evaluated to determine whether the component intended function is affected, and a corrective action is implemented.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be implemented prior to the period of extended operation.

As a result of the response to RAI 3.0.3-2 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.26, page B-162, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

B.2.1.26 Lubricating Oil Analysis

Program Description

The Lubricating Oil Analysis aging management program is an existing preventive and mitigative program that ensures the oil environment in mechanical systems subject to aging management review is maintained to the required quality to prevent or mitigate age-related degradation of components within the scope of this program. The Lubricating Oil Analysis program maintains oil systems contaminants within acceptable limits through periodic sampling and analysis, and comparing the analytical results to pre-determined limits that are associated with corrective actions such as filtering or oil replacement in order to manage the aging effects of loss of material due to corrosion or reduction of heat transfer due to fouling. The program directs scheduled activities that include routine sampling, analyses, and trending, thereby, preserving an oil environment in piping, piping components, piping elements, valve bodies, pump casings, gear boxes, tanks, and heat exchangers that is not conducive to loss of material or reduction of heat transfer. The lubricating oil testing (sampling and analysis) and condition monitoring activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. ***The sampling activities included in this program are sufficient to detect particulate indicative of degradation or failure of internal linings or coatings.*** The oil contaminant levels (e.g., water and particulates) are trended. Any result that is outside of the acceptance criteria is entered into the corrective action program to evaluate the condition, which could include in-leakage***,*** ~~or~~ corrosion product buildup ***or loss of coating integrity for coated or lined components***, and implement corrective actions such as component repairs, filtering, or oil replacement to maintain the lubricating oil contaminants within acceptable limits.

To verify the effectiveness of the Lubricating Oil Analysis program, selected components will be inspected as described in the One-Time Inspection (B.2.1.20) program, to ensure that age-related degradation is not occurring and component intended functions are maintained during the period of extended operation.

As a result of the responses to RAI's B.2.1.28-1, B.2.1.28-3, and B.2.1.28-4 provided in Enclosure A of this letter, LRA Appendix B, Section B.2.1.28, pages B-175, B-178, and B-179, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

B.2.1.28 Buried and Underground Piping

Exceptions to NUREG-1801

1. NUREG-1801, Chapter XI.M41, as modified by LR-ISG-2011-03, states buried carbon steel pipe should be coated in accordance with Table 1 of NACE SP0169-2007. Buried piping and components embedded in reinforced concrete are not coated ~~(Byron only)~~. **Program Elements Affected: Preventive Actions (Element 2)**

   Justification for Exception

   Original plant specifications do not require coatings to be installed for carbon steel piping embedded in reinforced concrete. The reinforced concrete provides superior corrosion protection for the embedded piping such that coatings are not necessary. Given the inaccessibility of piping embedded in concrete, installation of new coatings is not practical. However, upon opportunistic excavation, the condition of the concrete which encases the piping shall be examined for indications of degradations that could adversely impact the embedded piping. Recent opportunistic inspections of below grade reinforced concrete surfaces at Byron and Braidwood Stations have shown the reinforced concrete to be in good condition. Additionally, direct inspections of buried piping fully backfilled in controlled low strength material has shown the cementitious material to be in good condition and providing superior protection for the piping. Therefore, there is reasonable assurance that the components embedded in reinforced concrete will continue to perform their intended function.

Enhancements

Prior to the period of extended operation, the following enhancements will be implemented in the following program elements:

7. Inspection quantities of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10 year period, beginning 10 years prior to the period of extended operation.
   a. ***The piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications (Byron only).***

Program Elements Affected: Detection of Aging Effects (Element 4)

9. In performing cathodic protection surveys, only the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness~~, unless the -100mV polarization criteria can be demonstrated effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured~~. ***Alternatively, soil corrosion, or electric resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys.*** An upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings. **Program Elements Affected: Acceptance Criteria (Element 6)**

Enclosure C

Byron and Braidwood Stations, Units 1 and 2

License Renewal Commitment List Changes

This Enclosure identifies commitments made in this document and is an update to the Byron and Braidwood Station (BBS) LRA Appendix A, Table A.5 License Renewal Commitment List. Any other actions discussed in the submittal represent intended or planned actions and are described to the NRC for the NRC's information and are not regulatory commitments. Changes to the BBS LRA Appendix A, Table A.5 License Renewal Commitment List are as a result of the Exelon response to the following RAI:

Appendix A, Table A.5 License Renewal Commitment number / Program	RAI number
17/ Aboveground Metallic Tanks	RAI B.2.1.17-1 RAI B.2.1.17-2
20 / One-Time Inspection	RAI B.2.1.23-1
23 / External Surfaces Monitoring of Mechanical Components	RAI 3.0.3-3 RAI B.2.1.23-1
25 / Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	RAI B.2.1.25-1
28 / Buried and Underground Piping	RAI B.2.1.28-3 RAI B.2.1.28-4

Notes:

- To facilitate understanding, portions of the original License Renewal Commitment List have been repeated in this Enclosure, with revisions indicated.
- Existing LRA text is shown in normal font. Changes are highlighted with ***bold italics*** for inserted text and ~~strikethroughs~~ for deleted text.

As a result of the responses to RAIs B.2.1.17-1 and B.2.1.17-2 provided in Enclosure A of this letter, LRA Appendix A, Table A.5 License Renewal Commitment List, line item 17 on page A-76 and A-77, is revised as shown below. The RAI that led to this commitment modification is listed in the "SOURCE" column. Any other actions described in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

A.5 LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
17	Aboveground Metallic Tanks	Aboveground Metallic Tanks is a new program that manages aging effects of loss of material ***and cracking*** on the external surfaces of aboveground metallic tanks within the scope of license renewal by performing periodic visual inspections ***once per eighteen (18) month operating cycle*** for degradation of the external surface of the ~~tank,~~ ***insulation*** lagging, flashing, ~~insulation,~~ roof~~ing~~, and accessible sealant. ***The program also requires periodic visual inspections and liquid penetrant examinations of the tank external surfaces at 25 locations for both tanks combined per site and includes, on a sampling basis, removal of selected tank lagging and insulation to permit inspections of the external tank surfaces and exposed sealants. The tank external surface inspections and examinations will be performed each 10-year period starting 10 years prior to the period of extended operation. The sample locations will include at least four locations below penetrations through the insulation and its jacketing (e.g. instrument nozzles, tank heaters, ladder). The remaining sample locations will be distributed such that inspections will occur on the tank dome, sides, and near the bottom.*** ~~Program effectiveness is determined by measuring the thickness of the tank bottoms to ensure that significant age-related degradation is not occurring.~~ ***One-time tank bottom ultrasonic inspections (one CST per station) will be performed within the 5-year period prior to the period of extended operation. The cathodic protection availability and effectiveness criteria in LR-ISG-2011-03 Table 4c, notes 3.ii and 3.iii, respectively, will be required to be met commencing 5 years prior to the PEO and during the PEO.*** ~~Tank bottom UT inspections will be performed within the five (5) year period prior to the period of extended operation, between years five (5) and ten of the period of extended operation, and whenever a tank is drained.~~	Program to be implemented prior to the period of extended operation. UT inspection schedule identified in commitment	Section A.2.1.17 ***Exelon letter RS-14-003 1/13/2014*** ***RAI B.2.1.17-1*** ***RAI B.2.1.17-2***

As a result of the responses to RAI B.2.1.23-1 provided in Enclosure A of this letter, LRA Appendix A, Table A.5 License Renewal Commitment List, line item 20 on page A-79, is revised as shown below. The RAI that led to this commitment modification is listed in the "SOURCE" column. Any other actions described in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments. Additions are indicated with ***bolded italics***.

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
20	One-Time Inspection	One-Time Inspection is a new program that will be used to verify the system-wide effectiveness of the Water Chemistry, Fuel Oil Chemistry and Lubricating Oil Analysis programs. ***The One-Time Inspection aging management program will also be utilized, in specific cases where existing data is insufficient:*** ***a. to validate that a particular aging effect is not occurring, or*** ***b. to verify that the aging effect is occurring slowly enough to not affect a components intended function during the period of extended operation.*** ***In these cases, the components will not require additional aging management.***	Program to be implemented prior to the period of extended operation. One-time inspections will be performed within the ten year period prior to the period of extended operation.	Section A.2.1.20 ***Exelon letter RS-14-003 1/13/2014*** ***RAI B.2.1.23-1***

As a result of the response to RAI 2.1.23-1 and RAI 3.0.3-3 provided in Enclosure A of this letter, LRA Appendix A, Table A.5 License Renewal Commitment List, line item 23 on page A-80, is revised as shown below. The RAI that led to this commitment modification is listed in the "SOURCE" column. Any other actions described in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments. Additions are indicated with ***bolded italics***.

A.5 LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
23	External Surfaces Monitoring of Mechanical Components	External Surfaces Monitoring of Mechanical Components is a new program that manages aging effects of metallic and elastomeric materials through periodic visual inspection of external surfaces for evidence of loss of material ***and cracking.*** Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. ***Periodic representative inspections to detect corrosion (i.e., loss of material) under insulation will be conducted on in-scope indoor insulated components, where the process fluid temperature is below the dew point for a period of time sufficient to accumulate condensation, and in-scope outdoor insulated components (with the exception of the condensate storage tanks). These periodic inspections will be conducted during each 10-year period of the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material due to general, pitting, or crevice corrosion, beyond that which could have been present during initial construction.*** ***If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation (e.g., water seepage through insulation seams/joints), then periodic inspections under insulation to detect corrosion under insulation will continue.***	Program to be implemented prior to the period of extended operation.	Section A.2.1.23 ***Exelon letter RS-14-003 1/13/2014*** ***RAI 2.1.23-1*** ***RAI 3.0.3-3***

As a result of the response to RAI B.2.1.25-1, LRA Appendix A, Table A.5 License Renewal Commitment List, line item 25 on page A-80 is revised as shown below. The RAI that led to this commitment modification is listed in the "SOURCE" column. Any other actions described in this submittal represent intended or planned actions. They are described for the NRC's information, and are not regulatory commitments. Additions are indicated with ***bolded italics***.

A.5 LICENSE RENEWAL COMMITMENT LIST

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
25	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is a new program that manages aging effects of metallic and elastomeric materials through visual inspections of internal surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers. ***This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement.***	Program to be implemented prior to the period of extended operation.	Section A.2.1.25 ***Exelon letter RS-14-003 1/13/2014*** ***RAI B.2.1.25-1***

As a result of the responses to RAI B.2.1.28-3 and B.2.1.28-4 provided in Enclosure A of this letter, Item 28 on pages A-80 through A-82 of LRA Appendix A, Section A.5, is revised to modify enhancement 7 and enhancement 9, as shown below. The RAIs that led to this commitment modification are listed in the "SOURCE" column. Any other actions described in this submittal represent intended or planned actions. They are described for the NRC's information and are not regulatory commitments. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
28	Buried and Underground Piping	Buried and Underground Piping is an existing program that will be enhanced to: 7. Inspection quantities of underground piping within the scope of license renewal will be performed in accordance with LR-ISG-2011-03, Element 4, Table 4b, during each 10 year period, beginning 10 years prior to the period of extended operation. ***a. The piping and components inside the Byron 0SX138A and 0SX138B valve vaults will be visually inspected by engineering on a quarterly basis until either measures to prevent immersion of the piping and components inside the vault are implemented, or a coating system is installed that is designed for periodic immersion applications (Byron only)[Note 3].*** 9. In performing cathodic protection surveys, only the -850mV polarized potential criterion specified in NACE SP0169-2007 for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness~~, unless the -100mV polarization criteria can be demonstrated effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured~~. ***Alternatively, soil corrosion, or electrical resistance, probes may also be used to demonstrate cathodic protection effectiveness during the annual surveys.*** An upper limit of -1200mV for pipe-to-soil potential measurements of coated pipes will also be established, so as to preclude potential damage to coatings.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.28 ***Exelon letter RS-14-003 1/13/2014*** ***RAI B.2.1.28-4*** ***RAI B.2.1.28-3***