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

December 13, 2013

Mr. Michael P. Gallagher
Vice President, License Renewal Projects
Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, PA 19348

SUBJECT: 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)

Dear Mr. Gallagher:

By letter dated May 29, 2013, Exelon Generation Company, LLC, submitted an application pursuant to Title 10 of the *Code of Federal Regulations* Part 54, to renew operating licenses NPF-37, NPF-66, NPF-72, and NPF-77 for Byron Nuclear Station, Units 1 and 2, and Braidwood Nuclear Station, Units 1 and 2, respectively, for review by the U.S. Nuclear Regulatory Commission staff. The staff is reviewing the information contained in the license renewal application and has identified, in the enclosure, areas where additional information is needed to complete the review.

These requests for additional information were discussed with John Hufnagel, and a mutually agreeable date for the response is within 30 days from the date of this letter. If you have any questions, please contact me at 301-415-3873 or by e-mail at john.daily@nrc.gov.

Sincerely,

John W. Daily, Sr. Project Manager
Projects Branch 1
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-454, 50-455, 50-456, and 50-457

Enclosure:
As stated

cc: Listserv

December 13, 2013

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Vice President, License Renewal Projects
Exelon Generation Company, LLC
200 Exelon Way
Kennett Square, PA 19348

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BYRON NUCLEAR STATION, UNITS 1 AND 2
AND BRAIDWOOD NUCLEAR STATION, UNITS 1 AND 2
REQUEST FOR ADDITIONAL INFORMATION
AGING MANAGEMENT, SET 2
(TAC NOS. MF1879, MF1880, MF1881, AND MF1882)

RAI 3.0.3-1, Recurring internal corrosion (000)

Applicability: Byron Nuclear Station (Byron) and Braidwood Nuclear Station (Braidwood)

Background:

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

Issue:

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 three 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.

Request:

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.

RAI 3.0.3-2, Loss of coating integrity for Service Level III and Other coatings (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 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.

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).

Request:

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.

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

Applicability: Byron and Braidwood

Background:

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.

Issue:

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.

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 PEO, 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 riod 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.

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.

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

Applicability: Byron

Background:

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.

Issue:

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.

Request:

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

RAI B.2.1.28-3, Cathodic protection millivolt polarization criteria (035)
Applicability: Byron and Braidwood

Background:

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.

Issue:

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.

Request:

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.

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.

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."

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 100°F, 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.

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

Applicability: Byron and Braidwood

Background:

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."

Issue:

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.

Request:

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.

SUBJECT: REQUESTS FOR ADDITIONAL INFORMATION FOR THE REVIEW OF THE BYRON STATION, UNITS 1 AND 2, AND BRAIDWOOD STATION, UNITS 1 AND 2, LICENSE RENEWAL APPLICATION – AGING MANGEMENT, SET 2 (TAC NOS. MF1879, MF1880, MF1881, AND MF1882)

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