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10 CFR 50
10 CFR 51
10 CFR 54

RS-14-051

February 27, 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 8, dated February 6, 2014 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 February 6, 2014, "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 8 (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 this request 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 2-27-2014

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 3.1.1-1**, Corrosion of external steel surfaces with elevated temperatures in LRA Section 3.1 (010)

Applicability: Byron and Braidwood

Background:

License Renewal Application (LRA) Tables 3.1.2-1 and 3.1.2-4 include carbon and low alloy steel (with or without stainless steel cladding) pressurizer and steam generator components exposed to air with borated water leakage. LRA Table 3.0-1 states that the air with borated water leakage environment is similar to the air-indoor uncontrolled environment, which is described as an environment where the surfaces of components may be wetted, but only rarely.

For the aging management review (AMR) items associated with item 3.1.1-49 and plant-specific notes 3 (Table 3.1.2-1) and 4 (Table 3.1.2-4), the LRA states that loss of material due to general, pitting, and crevice corrosion is not applicable. The plant-specific notes state that the components have an external temperature greater than 212 ºF and, therefore, wetting due to condensation and moisture accumulation will not occur.

SRP-LR Section A.1.2.1, “Applicable Aging Effects,” item 7, states, “[t]he applicable aging effects to be considered for license renewal include those that could result from normal plant operation, including plant/system operating transients and plant shutdown.”

Issue:

The staff noted that, during refueling outages, the subject pressurizer and steam generator components may be at ambient temperatures for prolonged periods of time, which may or may not be above the dew point. Therefore, they may be susceptible to a condensation environment during outages. The plant-specific notes did not provide a basis for why corrosion is not expected to occur during plant outages.

The Generic Aging Lessons Learned (GALL) Report recommends that GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components," be used to manage loss of material due to general, pitting, and crevice corrosion for steel components exposed to uncontrolled indoor air.

Request:

Provide the technical basis or operating experience to justify why loss of material due to general, pitting, and crevice corrosion is not an applicable aging effect for the subject pressurizer and steam generator components, given that, during normal plant events such as refueling outages, these components will be at or near ambient temperatures. Alternatively, provide AMR items that describe how this aging effect will be managed.

**Exelon Response:**

The plant-specific notes referenced in the *Background* Section and related to LRA Table 3.1.2-1 and 3.1.2-4 only address external surface conditions during normal power operations where external surfaces of pressurizer and steam generator components are greater than 212°F. During refueling outages it is reasonable to conclude that significant condensation and moisture accumulation will not occur. Condensation and moisture accumulation will not occur on surfaces with temperatures greater than the dew point temperature of the surrounding air. The containment ventilation system is placed in service during refueling outages to dehumidify and reduce containment air dew point temperature below the temperatures of the external surfaces of the pressurizer and steam generators, thereby, preventing condensation and moisture accumulation. In addition, the pressurizer and steam generators are insulated, which would tend to decrease cooling of the surfaces of these components.

Shortly after the reactor is shutdown, personnel enter containment and commence refueling activities. To provide for a comfortable work environment, a minimum of one (1) reactor containment fan cooler (RCFC) fan and one (1) associated essential service water cooling coil is kept in service throughout most of the refueling outage to control containment air temperature and humidity.

The RCFC fan(s) are only taken out of service for short durations during critical refueling activities, such as the reactor head lift, to minimize the potential for the spread of contamination. For these short durations, collectively estimated to be less than 24 hours, minor condensation may occur. However, significant surface water accumulation during this time is not expected. Any minor accumulation would evaporate when the RCFC fan(s) are placed back in service or when the unit heats up for start up. Therefore, since loss of material is a time dependent factor, each of these short and intermittent intervals would not contribute any appreciable amount of corrosion.

The above conclusions are supported by Byron and Braidwood operating experience. Key word searches of the Byron and Braidwood Station Passport Action Request (AR) database related to the Reactor Coolant Systems, Reactor Vessel Systems, and the Steam Generator Systems identified no corrective action reports identifying loss of material on external surfaces of the pressurizer or steam generators. Also, direct visual evidence from previous maintenance activities have shown that no significant loss of material due to condensation has occurred on these components.

Therefore, the aging effect of loss of material due to general, pitting, and crevice corrosion due to condensation and moisture accumulation during refueling outages is not considered applicable for external surfaces on the pressurizer and steam generators.

As a result of this RAI, the two plant specific notes are revised to clarify that aging effects for these components were considered for normal plant operation and plant shutdown. Accordingly, LRA Table 3.1.2-1, Reactor Coolant System plant specific note 3 and LRA Table 3.1.2-4, Steam Generators, plant specific note 4 are revised as shown on Enclosure B.

**RAI 3.2.2-1**, Corrosion of external steel surfaces in LRA Sections 3.2, 3.4, and 3.5 (010)

Applicability: Byron and Braidwood

Background:

LRA Sections 3.2, 3.4, and 3.5 include several carbon steel components exposed externally to air with borated water leakage for which there is only an AMR item for loss of material due to boric acid corrosion. Conversely, other carbon steel components exposed externally to air with borated water leakage also have a second AMR item for loss of material due to general, pitting, and crevice corrosion. The LRA does not include an explanation for this discrepancy. Components without the second AMR item are present in, but are not necessarily limited to, LRA Tables 3.2.2-1, 3.2.2-2, 3.4.2-1, 3.5.2-3 (graphitic tool steel), and 3.5.2-15.

The staff noted that LRA Table 3.0-1 states that the air with borated water leakage environment is similar to the air-indoor uncontrolled environment, which is described as an environment where the surfaces of components may be wetted, but only rarely. The GALL Report recommends that loss of material due to general, pitting, and crevice corrosion be managed for steel components exposed to uncontrolled indoor air.

Issue:

It is not clear to the staff why some steel components exposed to air with borated water leakage in LRA Sections 3.2, 3.4, and 3.5 are not managed for loss of material due to general, pitting, and crevice corrosion. The GALL Report cites this aging effect for steel exposed to uncontrolled indoor air.

Request:

Provide the technical basis to justify why loss of material due to general, pitting, and crevice corrosion is not an applicable aging effect for several steel components exposed to air with borated water leakage in LRA Sections 3.2, 3.4, and 3.5 (and other sections, if applicable). Alternatively, provide AMR items for this aging effect.

**Exelon Response:**

LRA Tables 3.2.2-1, 3.2.2-2, 3.4.2.-1, 3.5.2-3, and 3.5.2-15 were reviewed for steel components exposed to air with borated water leakage. Based upon this review, it was determined that the loss of material aging effect due to general corrosion for steel components exposed to an air with borated water leakage should have been included for a number of component types. Steel components exposed to an indoor air with borated water leakage environment are susceptible to loss of material due to boric acid corrosion, managed by the Boric Acid Corrosion (B.2.1.4) aging management program; and, loss of material due to general corrosion, managed by aging management programs such as Structures Monitoring (B.2.1.34), External Surfaces Monitoring of Mechanical Components (B.2.1.23), and ASME Section XI, Subsection IWF. Other LRA sections were also reviewed as part of an extent of condition assessment; however, no other applicable instances were identified. Therefore, LRA Tables 3.2.2-1, 3.2.2-2, 3.4.2-1, 3.5.2-3, and 3.5.2-15 are revised, as shown in Enclosure B of this letter, to include the loss of material due to general corrosion aging effect.

**RAI 3.1.2-1**, Use of the Bolting Integrity program to manage the aging of structural bolting (019)

Applicability: Byron and Braidwood

Background:
LRA Table 3.1.2-1, Reactor Vessel, includes AMR items for carbon and low alloy steel structural bolting, for which loss of material and loss of preload are managed by the Bolting Integrity program. LRA Section B.2.1.9 states that the Bolting Integrity program addresses closure bolting on pressure retaining joints and that the aging of structural bolting is managed by the ASME Section XI, Subsection IWF program, Structures Monitoring Program, or the Regulatory Guide (R.G.) 1.127, Inspection of Water Control Structures Associated with Nuclear Power Plants program.

GALL Report AMP, XI.M18, "Bolting Integrity," recommends that the aging of structural bolting be managed by AMPs XI.S1, "ASME Section XI, Subsection IWE"; XI.S3, "ASME Section XI, Subsection IWF"; XI.S6, "Structures Monitoring"; XI.S7, "RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"; and XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems."

Issue:

The LRA assigned the Bolting Integrity program to manage the aging of carbon and low alloy steel structural bolting in the reactor vessel; however, neither the LRA program nor the GALL Report program addresses structural bolting. The staff noted that Bolting Integrity program includes inspections for leakage as an indication of bolting degradation, which is only applicable to closure bolting that retains pressure.

Request:

State the specific inspection activities in the Bolting Integrity program that address the aging of carbon and low alloy steel structural bolting in the reactor vessel and revise LRA Section B.2.1.9 to reflect that the Bolting Integrity program manages structural bolting. Alternatively, provide an appropriate AMP that manages the identified aging effects for the subject bolting.

**Exelon Response:**

The *Background* section of this RAI incorrectly identifies LRA Summary of Aging Management Evaluation Table 3.1.2-1, as associated with Reactor Vessel System. LRA Table 3.1.2-1 is associated with the Reactor Coolant System and does not contain AMR line items for carbon and low alloy steel structural bolting. LRA Table 3.1.2-2 addresses Reactor Vessel System, and on page 3.1-70 includes an AMR line item for carbon and low alloy steel structural bolting that credits the Bolting Integrity program.

LRA Table 3.1.2-2, Reactor Vessel, on page 3.1-70, includes an AMR line item for a "Bolting (Structural)" component type, with a "Structural Support" intended function, with "Carbon and Low Alloy Steel Bolting" material, in an "Air with Borated Water Leakage (External)" environment for which "loss of material" and "loss of preload" are managed by the Bolting Integrity Program (B.2.1.9). This AMR line item evaluates bolts that fasten mechanical elements of the integral reactor vessel head assembly described in LRA Section 2.3.1.2, Reactor Vessel, and in UFSAR Section 9.1.4.2.2, Component Description, Integral Reactor Vessel Head Assembly.

At Byron and Braidwood, the integral reactor vessel head assembly (IRVHA) was evaluated as a part of the Reactor Vessel System. The IRVHA is an assembly which combines the reactor vessel head lifting rig, seismic platform, lift columns, reactor vessel missile shield, control rod drive mechanism (CRDM) forced air cooling system, and electrical and instrumentation cable routing into an efficient, one-package reactor vessel head design. Structural elements of the IRVHA which are used to lift the reactor head are managed by the ASME Section XI, Subsection IWF (B.2.1.31) aging management program. Remaining bolts not managed by the ASME Section XI, Subsection IWF (B.2.1.31) aging management program also require aging management for loss of material and loss of preload.

Even though these bolts are not closure bolting on pressure retaining joints, the Bolting Integrity (B.2.1.9) aging management program was determined to be the appropriate aging management program to address the aging effects of “loss of preload” and “loss of material” for these bolts.

Specific inspection activities that detect loss of material and loss of preload for these bolts are contained in site system walkdown procedures, which are credited by the Bolting Integrity (B.2.1.9) aging management program. For all applicable systems, including the Reactor Vessel System, the procedure includes criteria such as, “no evidence of corrosion on bolting external surfaces”, “bolts/studs are present and have proper thread engagement in accordance with site design specification or typically two threads or greater above top of nut”, and “no evidence of the lack of bolting integrity” (i.e., loose nuts).

Accordingly, LRA section B.2.1.9, Bolting Integrity, is revised as shown in Enclosure B, to provide additional details to describe how the Bolting Integrity (B.2.1.9) aging management program will manage these bolts for the identified aging effects.

**RAI 3.5.2-1**, Component support bolting exposed to raw water (019)

Applicability: Byron only

Background:

LRA Table 3.5.2-3, Component Supports Commodity Group, contains an AMR item for stainless steel bolting exposed to raw water (Byron only) that is managed for loss of preload with the Structures Monitoring program. This component has an intended function of structural support and is associated with supports for the emergency diesel generator, HVAC system components, and other miscellaneous mechanical equipment. The LRA does not contain any other AMR items for the subject bolting in the raw water environment.

The GALL Report does not contain a specific AMR item for stainless steel structural bolting exposed to raw water. However, for other stainless steel components, such as piping, the GALL Report states that loss of material due to pitting, crevice, and microbiologically-influenced corrosion is an applicable aging effect in raw water environments (e.g., GALL Report item VII.H2.AP-55).

Issue:

It is not clear to the staff why the stainless steel structural bolting exposed to raw water (Byron only) in the component supports commodity group is not managed for loss of material. The GALL Report cites this aging effect for stainless steel components exposed to a raw water environment.

Request:

Provide the technical basis to justify why loss of material due to pitting, crevice, and microbiologically-influenced corrosion is not an applicable aging effect for the stainless steel structural bolting exposed to raw water (Byron only) in LRA Table 3.5.2-3. Alternatively, provide an AMR item for this aging effect and, if applicable, describe the inspection method and frequency for the submerged bolting.

**Exelon Response:**

LRA Table 3.5.2-3, Component Supports Commodity Group, was reviewed for stainless steel bolting exposed to a raw water environment. Based on this review, it was determined that the loss of material aging effect due to pitting, crevice, and microbiologically-influenced corrosion should have been included for stainless steel bolting associated with the supports for emergency diesel generator, HVAC system components, and other miscellaneous mechanical equipment component type. The loss of material aging effect will be managed by the Structures Monitoring (B.2.1.34) program, which includes visual inspections performed at least once every five (5) years.

LRA Table 3.5.2-3 is revised, as shown in Enclosure B of this letter, to include the loss of material aging effect due to pitting, crevice, and microbiologically-influenced corrosion for this component type, material, and environment combination.

**RAI 3.1.2.2.6-1,** Condition monitoring activities for SCC of CASS components (073)

Applicability: Byron and Braidwood

Background:

Item 3.1.1-20 in LRA Table 3.1.1 addresses cracking due to stress corrosion cracking (SCC) of cast austenitic stainless steel (CASS) piping components that do not meet the NUREG-0313 guidelines for material selection. LRA Item 3.1.1-20 indicates that cracking due to SCC for these components will be managed by the applicant's Water Chemistry program and ASME Section XI Inservice Inspection (ISI) program. Specifically, LRA Table 3.1.2-1 for the reactor coolant system indicates that cracking of the reactor coolant pressure boundary (RCPB) CASS piping will be managed by using LRA Item 3.1.1-20, consistent with GALL Report Item IV.C2.R-05.

In addition, LRA Section 3.1.2.2.6, Item 2 addresses applicant's further evaluation for aging management for the CASS components associated with LRA Item 3.1.1-20. LRA Section 3.1.2.2.6, Item 2 states that the ISI program includes condition monitoring activities for these RCPB CASS components to ensure that there is no loss of intended function.

Issue:

LRA Section 3.1.2.2.6.2 does not provide specific information on "condition monitoring activities" to demonstrate the adequacy of applicant's aging management. For example, additional information is necessary as to how the conditions of these CASS components will be monitored and what inspection method will be used to manage cracking for these CASS components.

Request:

Provide additional information on the "condition monitoring activities" to demonstrate the adequacy of applicant's aging management for these CASS components (e.g., how the conditions of these CASS components will be monitored and what inspection method will be used).

**Exelon Response:**

The ASME Class 1 cast austenitic stainless steel (CASS) components at Byron and Braidwood consists of the reactor coolant pipe fittings (elbows) for line item 3.1.1-20, IV.C2.R-05. The material screening criteria used to further evaluate and manage the aging effect and aging mechanism of cracking due to stress corrosion cracking of Class 1 cast austenitic stainless steel (CASS) components are consistent with the Generic Aging Lessons Learned Report item IV.C2.R-05. The recommended aging management programs for this aging effect and aging mechanism are the Water Chemistry program and a plant-specific program. The Byron and Braidwood CASS pipe fittings do not meet the NUREG-0313 exclusion guidelines of carbon content of less than or equal to 0.035 percent and ferrite content of greater than or equal to 7.5 percent. Therefore, Byron and Braidwood credit the Water Chemistry aging management program (B.2.1.2) and ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD aging management program (B.2.1.1) to manage the aging effect and aging mechanism of cracking due to stress corrosion cracking for the Class 1 CASS pipe fittings exposed to reactor coolant.

For CASS pipe fittings at Byron and Braidwood, the condition monitoring activities referred to in LRA Section 3.1.2.2.6.2 consist of either a visual examination, a qualified ultrasonic test (UT) examination method, or a pressurized leakage test to monitor cracking in CASS pipe fittings. Current UT methods cannot detect and size cracks, therefore, a visual examination is planned to be used until a qualified UT examination methodology for CASS pipe fittings can be developed to meet the ASME Section XI, Appendix VIII, "Performance Demonstration for Ultrasonic Examination Systems" requirements. However, this requires accessibility to the internal surface of the CASS pipe fittings. The CASS pipe fittings are presently monitored in the ASME Section XI Inservice Inspection (B.2.1.1) program by using a VT-2 examination at normal operating temperature and normal operating pressure. Exelon is working with ASME and EPRI to develop a qualified examination method for the detection of stress corrosion cracking in CASS components.

**RAI 4.7.8-1,** Flaw Evaluation Plant-specific TLAA (114)

Applicability: Byron and Braidwood

Background:

LRA Section 4.7.8 states that Byron and Braidwood Stations performed pre-emptive flaw evaluations on reactor vessel, pressurizer, primary steam generator sub-components, and primary coolant components. The LRA states that the evaluation methodology uses the number of design cycles as inputs to calculate conservative flaw growth and to develop crack growth reference curves for the components. The LRA states that these flaw evaluations are used to determine if flaws will propagate to unacceptable sizes. The LRA further states that the Fatigue Monitoring Program will be used to ensure that the number of transients used in the curves will not be exceeded during the period of extended operation.

Issue:

The staff is unclear which pressure and thermal transients were used in the flaw evaluation methodology. The staff is unclear which transients will be monitored by the Fatigue Monitoring Program to support the ASME Section XI crack growth analyses.

Request:

Provide the thermal and pressure transients that will be monitored by the Fatigue Monitoring Program to support the ASME Section XI crack growth analyses. For each transient, provide the number of design transient cycles assumed in the flaw evaluations.

**Exelon Response:**

The thermal and pressure transients and the number of design transient cycles assumed in the flaw evaluations that will be monitored by the Fatigue Monitoring program to support the ASME Section XI crack growth analyses are listed in Table 1 and Table 2, provided below. The tables contain only the design transient cycles assumed in the flaw evaluations and retain the original LRA table transient number, description, and CLB Cycle Limit.

One of the transients assumed in the flaw evaluation analyses has a design transient cycle value which is more limiting than CLB Cycle Limit presented in LRA Tables 4.3.1-1 and 4.3.1-4. For the Excessive Bypass Feedwater Flow transient, there is a difference in the CLB Cycle Limit of 40 cycles in the LRA table versus the 30 design transient cycles assumed in the Steam Generator flaw evaluation. The LRA credits the Fatigue Monitoring program to monitor the transients which are inputs to the flaw evaluation analysis. It should be noted the 60-year cycle projection for this transient is 2 cycles, which continues to assure a large margin to the new limiting value for future operations.

As a result of the response to this RAI, the CLB Cycle Limit for the Excessive Bypass Feedwater Flow transient is revised from 40 cycles to 30 cycles. Accordingly, LRA Table 4.3.1-1, and LRA Table 4.3.1-4 are corrected as shown in Enclosure B.

| Table 1<br>LRA Section 4.7.8 RCS Design Transient Cycles Assumed in Flaw Evaluations | | | | |
|---|---|---|---|---|
| **Component** | | **Steam Generators** | **Pressurizer** | **Reactor Vessel** |
| **Transient Number and Description from LRA Tables 4.3.1-1 and 4.3.1-4** | **CLB Cycle Limit from LRA Tables 4.3.1-1 and 4.3.1-4** | **Cycles in WCAP-11063** | **Cycles in WCAP-11063** | **Cycles in WCAP-12046** |
| 1. Plant Heatup at 100°F/hr | 200 | 200 | 200 | 200 |
| 2. Plant Cooldown at 100°F/hr | 200 | 200 | 200 | 200 |
| 3. Unit Loading Between 0% and 15% of Full Power | 330 | 1,500 | na | na |
| 4. Unit Unloading Between 15% and 0% of Full Power | 500 | 1,500 | na | na |
| 5. Unit Loading @ 5% of full power/min (15% to 100%) | 13,200 | na | 18,300 | 13,200 |
| 6. Unit Unloading @ 5% of full power/min (100% to 15%) | 12,240 | na | 18,300 | 13,200 |
| 7. 10% Step Load Increase | 2,000 | 2,000 | 2,000 | 2,000 |
| 8. 10% Step Load Decrease | 2,000 | 2,000 | na | 2,000 |
| 9. Large Step Load Decrease With Steam Dump | 200 | 200 | (Note 1) | 200 |
| 10. Steady State Fluctuations a. Initial | 150,000 | na | na | 150,000 |
| 11. Steady State Fluctuations b. Random | 3,000,000 | na | na | 3,000,000 |
| 12. Boron Concentration Equalization | 26,400 | na | 26,400 | 26,400 |
| 13. Feedwater Cycling at Hot Shutdown | 2,000 | 2,000 | na | 2,000 |
| 14. Loop Out of Service<br>Normal loop shutdown<br>Normal loop startup | <br>80<br>70 | <br>80<br>70 | <br>(Note 1)<br>(Note 1) | <br>na<br>na |
| 15. Refueling | 80 | na | na | 80 |
| 20. Loss of Load | 80 | 80 | (Note 1) | 80 |
| 21. Loss of Power | 40 | 40 | na | 40 |
| 22. Partial Loss of Flow | 80 | 80 | na | 80 |

| Table 1<br>LRA Section 4.7.8 RCS Design Transient Cycles Assumed in Flaw Evaluations | | | | | |
|---|---|---|---|---|---|
| **Component** | | **Steam Generators** | **Pressurizer** | **Reactor Vessel** |
| **Transient Number and Description from LRA Tables 4.3.1-1 and 4.3.1-4** | **CLB Cycle Limit from LRA Tables 4.3.1-1 and 4.3.1-4** | **Cycles in WCAP-11063** | **Cycles in WCAP-11063** | **Cycles in WCAP-12046** |
| 23. Reactor Trip from Full Power: Case A – with no inadvertent cooldown | 230 | 230 | na | 230 |
| 24. Reactor Trip from Full Power: Case B – with cooldown and no safety injection | 160 | 160 | na | 160 |
| 25. Reactor Trip from Full Power: Case C – with cooldown and safety injection | 10 | 10 | na | 10 |
| 26. Inadvertent RCS Depressurization | 20 | 20 | 540 | 20 |
| 27. Inadvertent Startup of Inactive Loop | 10 | 10 | (Note 1) | 10 |
| 28. Control Rod Drop | 80 | 80 | na | 80 |
| 29. Inadvertent Safety Injection (ECCS) Actuation | 60 | 60 | (Note 1) | 60 |
| 30. Excessive Feedwater Flow | 30 | 30 | na | 30 |
| 31. Bypass Line Tempering Valve Failure | 20 | 20 | na | na |
| 32. Excessive Bypass Feedwater Flow | 40 | 30 (Note 2) | na | na |
| 34. Operating Basis Earthquake (OBE) | 20 | 20 | 20 | na |
| 37. Turbine Roll Test | 20 | 20 | 20 | 20 |
| 38. Primary Side Hydrostatic Test | 10 | na | 10 | 10 |
| 39. Secondary Side Hydrostatic Test | 10 | 10 | na | na |
| 40. Primary Side Leakage Test | 200 | 200 | 200 | 280 |
| 41. Secondary Side Leakage Test | 80 | 80 | 200 | na |

| Table 1<br>LRA Section 4.7.8 RCS Design Transient Cycles Assumed in Flaw Evaluations | | | | |
|---|---|---|---|---|
| **Component** | | **Steam Generators** | **Pressurizer** | **Reactor Vessel** |
| **Transient Number and Description from LRA Tables 4.3.1-1 and 4.3.1-4** | **CLB Cycle Limit from LRA Tables 4.3.1-1 and 4.3.1-4** | **Cycles in WCAP-11063** | **Cycles in WCAP-11063** | **Cycles in WCAP-12046** |
| 42. Steam Generator Tube Leakage Test | 720 | 800 | na | na |

| Table 2<br>LRA Section 4.7.8 Auxiliary System Design Transient Cycles Assumed in Flaw Evaluations | | | | |
|---|---|---|---|---|
| **Component** | | **Steam Generators** | **Pressurizer** | **Reactor Vessel** |
| **Transient Number and Description from LRA Tables 4.3.1-2 and 4.3.1-5** | **CLB Cycle Limit from LRA Tables 4.3.1-2 and 4.3.1-5** | **Cycles in WCAP-11063** | **Cycles in WCAP-11063** | **Cycles in WCAP-12046** |
| 21. Pressurizer Spray and Auxiliary Spray Line Piping and Nozzles Transients | 10 | na | 10 | na |

na – not applicable

**Note:**

Note 1 - For the Pressurizer flaw evaluation, these transients were considered as a bundled group of transients with a transient cycle input value of 520 which bounds the CLB Cycle Limit total for these transient of 500.

Note 2 - All steam generator design specs and documentation consider a limit of 40 cycles. Since the input of 30 transient cycles to the steam generator flaw evaluation is less than the CLB Limit, the Fatigue Monitoring Program will be revised to use 30 transient cycles as the limit and the 30 cycles will be considered the CLB Cycle Limit.

**RAI B.2.1.12-1**, Opportunistic Inspections in the Closed Treated Water Systems Program (022)

Applicability: Byron and Braidwood

Background:

GALL Report AMP XI.M21A, “Closed Treated Water Systems,” recommends conducting visual inspections to detect aging whenever the system pressure boundary is opened (i.e., opportunistic inspections). The GALL Report AMP also states that inspections are conducted in accordance with applicable code requirements or the selected industry standard. Absent an applicable code or standard, plant-specific inspection and personnel qualification procedures capable of detecting corrosion or cracking may be used.

The program description in LRA Section B.2.1.12, Closed Treated Water Systems, and the program basis document, BB-PBD-AMP-XI.M21A, state that existing condition monitoring activities provide for opportunistic visual inspections. However, during the staff’s audit of the program, the staff was not able to confirm that the existing program includes inspections capable of detecting corrosion and cracking whenever the system boundary is opened.

Issue:

The existing Closed Treated Water Systems program appears to be inconsistent with GALL Report AMP XI.M21A with respect to the inclusion of opportunistic inspections. As a result, it is not clear to the staff whether the program is capable of detecting corrosion and cracking prior to loss of intended function.

The staff noted that site personnel receive general training to identify conditions in the plant on an ongoing basis; however, that practice does not include specific inspection and personnel qualification procedures to ensure that corrosion and cracking can be detected in the closed treated water systems.

Request:

1. If available, provide the portions of the implementing procedures for the Closed Treated Water Systems program that demonstrate that the existing program includes opportunistic inspections that are guided by specific inspection and personnel qualification procedures capable of detecting corrosion and cracking.

2. If the existing program does not include such opportunistic inspections, provide the technical justification that demonstrates that loss of material and cracking will be adequately managed. Alternatively, provide an enhancement to the program to include these inspections.

**Exelon Response:**

1. Opportunistic inspections of components within the scope of the Closed Treated Water Systems (B.2.1.12) aging management program are performed whenever the system boundary is opened. Existing station procedures require that, at a minimum, a general visual inspection of the internal surface of systems and components is performed immediately after the system or component is opened. Personnel performing these

inspections are qualified to Exelon job qualifications, and in accordance with the INPO National Academy for Nuclear Training accredited training program that meets industry standards. Training includes familiarization with system components, use of the corrective action program, and use of plant procedures. Additionally, the supervisor verifies that the individuals assigned to perform the inspections are qualified. The purpose of the opportunistic visual inspections is to ensure that existing environmental conditions are not causing unanticipated material degradation that could result in a loss of component intended functions. Age-related degradation would be visually detectable before the aging effect is reasonably expected to impair the ability of the component to perform its intended function. If age-related degradation is identified during opportunistic inspections, then the condition would be entered into the corrective action program.

Plant-specific operating experience indicates that the water chemistry controls have been effective in mitigating age-related degradation. To verify the effectiveness of the closed cooling water chemistry control in mitigating age-related degradation during the period of extended operation, the Closed Treated Water Systems (B.2.1.12) aging management program includes periodic visual inspections and non-destructive examinations of the internal surface of a representative sample of components within the scope of the program to demonstrate that loss of material, cracking, and reduction of heat transfer will be adequately managed. These mitigative measures and periodic inspections are the primary means by which aging is managed, and opportunistic inspections supplement these activities.

2. The existing Closed Treated Water Systems (B.2.1.12) aging management program includes opportunistic inspections as described in part 1 of this response.

Based on the above, the Closed Treated Water Systems (B.2.1.12) aging management program is revised to clarify that the program includes opportunistic inspections whenever the system boundary is opened. LRA Appendix A.2.1.12 and LRA Appendix B.2.1.12 are revised as shown in Enclosure B.

**RAI 3.5.2-2**, PVC conduit exposed to groundwater or soil (092)

Applicability: Byron and Braidwood

Background:

LRA Table 3.5.2-15 states that for polyvinyl chloride (PVC) conduit exposed to groundwater/soil, there is no aging effect and no AMP is proposed.

Issue:

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material and environmental combination. While the staff recognizes that there are no AMR items for PVC conduit exposed to groundwater/soil, the "scope of program" program element of LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks'," states, "[t]his program manages the effects of aging for buried and underground piping and tanks constructed of any material including metallic, polymeric, cementitious, and concrete materials." Although conduit is not within the scope of LR-ISG-2011-03, the ISG provides the staff insight that buried polymeric components have aging effects that should be managed. LRA Table 3.5.2-15 states that the intended functions of the buried conduit are shelter protection and structural support. Although these intended functions are different than that associated with buried piping, which is typically pressure boundary, leaks in the conduit could adversely impact the intended function of the cables that are inside the conduit if the cable jacketing was degraded.

The "program description" of GALL Report AMP XI.E3, "Inaccessible Power Cables not Subject to 10 CFR 50.49 Environmental Qualification Requirements," states:

> Most electrical cables in nuclear power plants are located in dry environments. However, some cables may be exposed to wetting or submergence, and are inaccessible or underground, such as cables in conduits, cable trenches, cable troughs, duct banks, underground vaults, or directly buried in soil installations. When a power cable (greater than or equal to 400 volts) is exposed to wet, submerged, or other adverse environmental conditions for which it was not designed, an aging effect of reduced insulation resistance may result, causing a decrease in the dielectric strength of the conductor insulation. This insulation degradation can be caused by wetting or submergence. This can potentially lead to failure of the cable's insulation system.

It is not clear to the staff how buried conduit with intended functions of shelter protection and structural support will have no aging effects and no recommended AMP.

Request:

State the basis for why potential aging effects for buried PVC conduit with intended functions of shelter protection and structural support are not being age-managed or propose an AMP to manage the aging effects.

**Exelon Response:**

Buried in-scope cables routed inside PVC conduits are embedded within reinforced concrete duct banks. The PVC conduits served to provide openings in the duct banks during concrete placement, and to aid in cable pulling and routing. The PVC conduit embedded in the reinforced concrete duct banks do not provide an intended function for license renewal, including shelter protection and structural support, as their failure would not impact a safety-related system, structure, or component. The reinforced concrete duct banks provide the shelter protection and structural support intended functions for these cables. Reinforced concrete duct banks are included within the scope of license renewal and are managed by the Structures Monitoring (B.2.1.34) program.

The groundwater/soil environment was applied to PVC conduit to account for possible situations where conduit penetrated out of a buried duct bank to grade-level. Based on further review of plant drawings at Byron and Braidwood Stations, no portions of PVC conduit routed directly in soil containing in-scope cables were identified. In locations where in-scope conduit is routed to grade-level, the conduit remains embedded in reinforced concrete duct banks. In the areas that conduit penetrates into other reinforced concrete structures, such as manholes, building foundations, and building walls, the reinforced concrete duct banks were poured flush up to the surface of the concrete structure.

As a result, LRA Table 3.5.2-15 is revised to remove the groundwater/soil environment for PVC conduit with intended functions of shelter protection and structural support, as shown in Enclosure B of this letter.

**RAI 3.5.2-3,** Polymeric conduit exposed to air-indoor uncontrolled environment (092)

Applicability: Byron and Braidwood

Background:

LRA Table 3.5.2-15 states that for polymeric conduit exposed to air-indoor uncontrolled, there is no aging effect and no AMP is proposed.

The AMR items cite plant specific note 2, which states, "[t]his material and environment applies to the vinyl covering on flexible, liquid-tight conduit in air-indoor environment. Based on plant operating experience, there are no aging effects requiring management for the combination of these materials and environments. The material in this environment is not expected to experience significant aging effects."

Issue:

The staff noted that vinyl materials can be supplied in a wide range of compositions. Depending upon the composition, environmental factors such as temperature, radiation, and proximity to fluorescent lighting which emits ultraviolet radiation can affect the manner in which the component ages. The staff lacks sufficient information to determine that there are no aging effects associated with these components.

Request:

1. State the specific composition of the vinyl covering on flexible, liquid-tight conduit.
2. State the specific values (e.g., maximum operating temperature, expected integrated dose for 60 years, ultraviolet levels) of environmental factors in the various or worst case locations where the vinyl covering on flexible, liquid-tight conduit is located.
3. State the basis for why there are no aging effects to manage for the vinyl covering on flexible, liquid-tight conduit or propose an aging management program to manage the aging effects.

**Exelon Response:**

1. The specific composition of the vinyl polymer covering on the flexible, liquid-tight conduit is not known.
2. The specific values (e.g., maximum operating temperature, expected integrated dose for 60 years, ultraviolet levels) of environmental factors in the various or worst case locations where the vinyl covering on flexible, liquid-tight conduit is located are not known.
3. The potential aging effects of the polymer vinyl covering as a result of exposure to ionizing and ultraviolet radiation, and elevated temperatures include a change in material properties. The manufacturer data sheets state that the material is UV and heat resistant. Since specific polymer composition and limiting plant operating conditions (i.e., temperatures, integrated dose and ultraviolet levels) have not been identified, the Structures Monitoring (B.2.1.34) program will be used to manage the polymer vinyl covering on the flexible, liquid-tight conduit.

LRA Table 3.5.2-15 is revised to reflect the changes discussed above, and is included in Enclosure B.

**<u>RAI 3.5.2-4</u>,** Thermal insulation aging effects for air-indoor uncontrolled or air with borated water leakage (092)

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

<u>Background:</u>

LRA Table 3.5.2-15, states that for thermal insulation exposed to air-indoor uncontrolled and air with borated water leakage and composed of calcium silicate, ceramic fiber, fiberglass, foamed plastic, and mineral fiber, there is no aging effect and no AMP is proposed.

The AMR items cite plant specific note 4, which states, "[o]perating experience has shown the air-indoor uncontrolled and air with borated water leakage environments to contain insignificant quantities of moisture, humidity, condensation, and contaminants during normal operation. Therefore, there are no aging effects associated with the insulation material in the normally dry, air - indoor uncontrolled and air with borated water leakage environments."

<u>Issue:</u>

The staff noted that:

- In a normally dry environment without the potential for water leakage, spray, or condensation, most insulation materials are expected to be inert to environmental effects. However, in moist environments, many insulation materials have been found to degrade. Some have the potential for prolonged retention of any moisture to which they are exposed; prolonged retention of moisture may increase thermal conductivity, thereby degrading the insulating characteristics, and also could accelerate the aging effects of insulated components.
- The description of air-indoor uncontrolled in LRA Table 3.0-1, Byron and Braidwood Service Environments," includes the statement, "[s]urfaces of components in this environment may be wetted, but only rarely; equipment surfaces are normally dry." Although the surfaces are only rarely wetted in this air environment, insulation can retain the moisture and its ability to reduce heat transfer will be degraded. The staff infers from the description of the air with borated water leakage environment that leakage from components in the vicinity could impact insulation.
- The staff lacks sufficient information to conclude that routine sweating of pipes that could drip onto insulation located below the pipe during humid conditions would be identified in the corrective action program and whether the insulation would be inspected for water damage and corrected as necessary.
- The description of ceramic fiber, fiberglass, and foamed plastic lack sufficient specificity to determine if these insulating materials can retain moisture if wetted. The staff believes that calcium silicate and mineral fiber insulation will retain moisture when wetted; at least for an indeterminate period of time.
- LRA Table 3.5.2-15 includes insulation jacketing which, if properly installed, provides protection from ambient moisture for the insulating materials.

Overall, the staff lacks sufficient information no conclude that thermal insulation exposed to air-indoor uncontrolled and air with borated water leakage and composed of calcium silicate, ceramic fiber, fiberglass, foamed plastic, and mineral fiber, has no aging effect.

Request:

1. For the above described insulation components in LRA Table 3.5.2-15 state:
    a. Whether all in-scope insulation is covered by jacketing; and
    b. how the configuration control plant-specific procedures for jacketing ensure that the jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams) such that it can be reasonably concluded that the thermal insulation exposed to air-indoor uncontrolled and air with borated water leakage and composed of calcium silicate, ceramic fiber, fiberglass, foamed plastic, and mineral fiber, has no aging effect.

2. If all in-scope insulation is not covered by jacketing or configuration control plant-specific procedures for jacketing, as described in Request 1b., do not exist, respond to the following:
    a. State the basis for why insulation without jacketing installed to configuration control plant-specific procedures for jacketing, as described in Request 1b has no aging effects in light of the potential for periodic moisture intrusion.
    b. State whether sweating of pipes during plant operation is identified as a condition adverse to quality in the corrective action program. If it is, provide evidence that either sweating is not occurring or that it has routinely been identified and corrected, including inspection of potentially wetted insulation.
    c. Provide sufficient information for the staff to determine if the ceramic fiber, fiberglass, and foamed plastic insulating materials can retain moisture if wetted.
    d. Alternatively to Requests 2a, 2b, and 2c, amend the LRA to include aging management of reduction of insulation effectiveness for in-scope thermal insulation.

**Exelon Response:**

1. Thermal insulation within the scope of license renewal exposed to air-indoor uncontrolled and air with borated water leakage performs a thermal insulation intended function if the insulation is required to prevent overheating of nearby safety-related SCCs (i.e., insulation for hot equipment located in areas with safety-related equipment). For hot equipment, even if moisture intrusion into thermal insulation due to leaks or sweating from nearby equipment occurs, it is not expected that the thermal insulation will retain the moisture since the heat from the equipment drives evaporation.

    The insulation components described in LRA Table 3.5.2-15 are addressed as follows:

    a. The majority of in-scope insulation consisting of calcium silicate, ceramic fiber, fiberglass, foamed plastic, and mineral fiber on piping, piping components, and tanks is covered by metallic jacketing in air-indoor and air with borated water leakage environments. The remaining in-scope insulation located indoors is covered by nonmetallic jacketing (i.e., water resistant coatings or fabrics). The in-scope insulation on outdoor piping, piping components, and tanks is covered by metallic jacketing.

    b. The specifications for insulation, which includes the jacketing, provide requirements to ensure that the jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams). In addition, based on a review of the corrective action program database, it is concluded that insulation not properly installed in accordance with the specifications would be identified during system walkdowns and appropriately corrected in accordance with the corrective action program. Therefore, it can be reasonably concluded that currently installed jacketing is properly installed so as to prevent water intrusion into the insulation.

Personnel knowledgeable of proper insulation installation requirements perform the insulation repairs. Although operating experience indicates that insulation is properly installed during repairs, a revision is required to the specific procedures or work order instructions for insulation and jacketing to formally document that the insulation and jacketing is properly installed during repairs so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams). Therefore, the new External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program is revised to document that insulation repairs are performed in accordance with the requirements of the specifications for insulation, as shown in Enclosure B. These additional requirements will be added to document that the insulation and jacketing is properly installed in accordance with specifications to prevent water intrusion into the insulation.

Since, with the revision described above, plant-specific configuration control procedures will exist for jacketing to ensure that the insulation and jacketing is properly installed so as to prevent water intrusion into the insulation, it is reasonably concluded that the insulation exposed to air-indoor uncontrolled and air with borated water leakage has no aging effects as long as the integrity of the jacketing is maintained. To ensure the integrity of the jacketing is maintained, the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program is revised to require visual inspections of the insulation jacketing as described in the response to *Request* 2 below. Visual inspections of the insulation jacketing will be performed to ensure that the insulation and jacketing are properly installed so as to prevent moisture intrusion into the insulation.

2. As described in the response to *Request* 1, insulation within the scope of license renewal is protected by metallic or nonmetallic (i.e., water resistant coatings or fabrics) jacketing, and plant-specific configuration control procedures for jacketing will ensure that the insulation and jacketing is properly installed so as to prevent water intrusion into the insulation. Therefore, responses to *Requests* 2a, 2b, and 2c are not required.

   In response to *Request* 2d, the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program is revised to require visual inspections of the in-scope insulation jacketing as part of the periodic system walkdowns to ensure that the integrity of the jacketing is maintained. The visual inspections, for loss of thermal insulation jacketing integrity, will ensure that the insulation and jacketing are properly installed so as to prevent moisture intrusion into the insulation. A review of site specific OE indicates that the only significant quantities of moisture in thermal insulation in indoor environments have been identified as part of the resolution of leakage from the insulated piping and components themselves, and not due to drips or sweating from nearby components. Therefore, it can be reasonably concluded that insulation and jacketing installation and configuration control processes will preclude a reduction of thermal insulation resistance, due to drips or sweating from nearby components, which could result in the overheating of nearby safety-related SCCs. Inspections of the insulation jacketing for signs of loss of thermal insulation jacketing integrity, performed as part of the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program, will ensure this conclusion remains valid through the period of extended operation.

As a result of the additional requirements described above, the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program is revised to document that future insulation repairs are performed in accordance with the requirements of the specifications for insulation and to require visual inspections of insulation jacketing during system walkdowns. As a result of this change, LRA Sections A.2.1.23 and 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, Item 23, is also revised as shown in Enclosure C. In addition, the following LRA sections and tables are revised, as a result of these changes, as described below.

LRA Table 3.4.1, Summary of Aging Management Evaluation for the Steam and Power Conversion System, is revised to add Item Numbers 3.4.1-64 and 3.4.1-65 as shown in Enclosure B.

LRA Section 3.5.2.1.15, Structural Commodity Group, is revised to include “loss of thermal insulation jacketing integrity” as an applicable aging effect for insulation jacketing and to credit the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program to manage the aging effects, as shown in Enclosure B.

LRA Table 3.5.2-15, Structural Commodity Group, is revised to add a plant specific note regarding aging management of insulation, to add an aging effect of “loss of thermal insulation jacketing integrity,” and to credit the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program for managing the aging of insulation jacketing in air-indoor uncontrolled and air with borated water leakage environments as shown in Enclosure B.

This RAI response only addresses the potential for reduced thermal insulation resistance. The potential for corrosion of in-scope components under insulation, and the aging management requirements, have been addressed in the response to RAI 3.0.3-3, included in Exelon letter RS-14-003, dated January 13, 2014.

# Enclosure B

## Byron and Braidwood Stations, Units 1 and 2
## License Renewal Application (LRA) updates
## resulting from the responses to the following RAIs:

RAI 3.1.1-1
RAI 3.2.2-1
RAI 3.1.2-1
RAI 3.5.2-1
RAI 4.7.8-1
RAI 3.5.2-2
RAI 3.5.2-3
RAI B.2.1.12-1
RAI 3.5.2-4

Note: 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 response to RAI 3.1.1-1 provided in Enclosure A of this letter, LRA Table 3.1.2-1 plant specific note 3 on page 3.1-69 is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

**Table 3.1.2-1 Reactor Coolant System (Continued)**

**Plant Specific Notes:**

3. ***During power operation,*** ~~T~~***t***he carbon steel components of the pressurizer have an external temperature greater than 212 degrees Fahrenheit ***and are at a greater temperature than the air-indoor (uncontrolled) environment/air with borated water leakage***. ***During refueling outages, the containment ventilation system is placed in service to dehumidify and reduce containment air dew point temperatures.*** Therefore, wetting due to condensation and moisture accumulation will not occur ***during power operation or refueling outages***, and loss of material (due to general, pitting, and crevice corrosion) is not applicable.

As a result of the response to RAI 3.1.1-1 provided in Enclosure A of this letter, LRA Table 3.1.2-4 plant specific note 4 on page 3.1-122 is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

**Table 3.1.2-4** **Steam Generators** **(Continued)**

**Plant Specific Notes:**

4. ***During power operation,*** ~~T~~***t***he carbon steel components of the Steam Generators, including the shell, nozzles, instrument bosses, and manways, have an external temperature greater than 212 degrees Fahrenheit and are at a ***greater*** ~~higher~~ temperature than the air-indoor (uncontrolled) environment/air with borated water leakage. ***During refueling outages, the containment ventilation system is placed in service to dehumidify and reduce containment air dew point temperatures.*** Therefore, wetting due to condensation and moisture accumulation will not occur ***during power operation or refueling outages***, and loss of material (due to general, pitting, and crevice corrosion) does not apply.

As a result of the response to RAI 3.2.2-1 provided in Enclosure A of this letter, LRA Table 3.2.1, Summary of Aging Management Evaluation for the Engineered Safety Features, page 3.2-24, is revised as shown below. Additions are indicated with ***bolded italics***.

**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 |
|---|---|---|---|---|---|
| 3.2.1-40 | Steel Ducting, piping, and components (External surfaces), Ducting, closure bolting, Containment isolation piping and components (External surfaces) exposed to Air – indoor, uncontrolled (External) | Loss of material due to general corrosion | Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components" | No | 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 steel encapsulation components, equipment supports and foundations, heat exchanger components, piping, piping components, piping elements, and tanks exposed to air – indoor uncontrolled and air with borated water leakage in the Auxiliary Building, ***Combustible Gas Control System,*** Containment Spray System, Reactor Coolant System, Reactor Vessel, Residual Heat Removal System, Safety Injection System, and Steam Generators. |

As a result of the response to RAI 3.2.2-1 provided in Enclosure A of this letter, LRA Table 3.2.2-1, Combustible Gas Control System, pages 3.2-33 and 3.2-34, is revised as shown below. Additions are indicated with ***bolded italics***.

**Table 3.2.2-1 Combustible Gas Control 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 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*** |
| Piping, piping components, and piping elements | Structural Support | Carbon Steel | 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*** |
| Valve Body | Pressure Boundary | Carbon Steel | 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*** |

As a result of the response to RAI 3.2.2-1 provided in Enclosure A of this letter, LRA Table 3.2.2-2, Containment Spray System, page 3.2-39, is revised as shown below. Additions are indicated with ***bolded italics***.

**Table 3.2.2-2 Containment Spray System (Continued)**

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Valve Body | Structural Support | Carbon Steel | Air with Borated Water Leakage (External) | Loss of Material | Boric Acid Corrosion (B.2.1.4) | V.A.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*** |

As a result of the response to RAI 3.5.2-4 provided in Enclosure A of this letter, LRA Table 3.4.1, Summary of Aging Management Evaluations for the Steam and Power Conversion System, page 3.4-32, is revised as shown below. Additions are indicated with ***bolded italics***.

**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 |
|---|---|---|---|---|---|
| ***3.4.1-64*** | ***Jacketed calcium silicate or fiberglass insulation in an air-indoor uncontrolled or air-outdoor environment*** | ***Reduced thermal insulation resistance due to moisture intrusion*** | ***Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"*** | ***No*** | ***Insulation within the scope of license renewal is covered by water resistant jacketing. Plant-specific configuration control procedures will ensure that jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams). Therefore, reduced thermal insulation resistance due to moisture intrusion is not an applicable aging effect for thermal insulation within the scope of license renewal as long as the integrity of the jacketing is maintained.***<br><br>***Visual inspections of jacketing are performed as part of the periodic system walkdowns included in the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program to ensure that loss of thermal insulation jacketing integrity does not occur.*** |

| 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** |
| ***3.4.1-65*** | ***Jacketed foamglas ® (glassdust) insulation in an air-indoor uncontrolled or air-outdoor environment*** | ***Reduced thermal insulation resistance due to moisture intrusion*** | ***Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"*** | ***No*** | ***Insulation within the scope of license renewal is covered by water resistant jacketing. Plant-specific configuration control procedures will ensure that jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams). Therefore, reduced thermal insulation resistance due to moisture intrusion is not an applicable aging effect for thermal insulation within the scope of license renewal as long as the integrity of the jacketing is maintained.***<br><br>***Visual inspections of jacketing are performed as part of the periodic system walkdowns included in the External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program to ensure that loss of thermal insulation jacketing integrity does not occur.*** |

As a result of the response to RAI 3.2.2-1 provided in Enclosure A of this letter, LRA Table 3.4.2-1, Auxiliary Feedwater System, pages 3.4-39 and 3.4-41, 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 Jacket Water Cooler) 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*** |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| Heat Exchanger - (AFW Right Angle Gear Oil Cooler) 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*** |

As a result of the response to RAI 3.5.2-4 provided in Enclosure A of this letter, LRA Appendix B, Section 3.5.2.1.15, page 3.5-20, is revised as shown below. Additions are indicated with ***bolded italics***.

### 3.5.2.1.15 Structural Commodity Group

#### Aging Effect Requiring Management

The following aging effects associated with the Structural Commodity Group components require management:

- Change in Material Properties
- Change in Material Properties, Loss of Material
- Cracking, Loss of Bond, and Loss of Material (Spalling, Scaling)
- Increase in Porosity and Permeability, Cracking, Loss of Material (Spalling, Scaling)
- ***Loss of thermal insulation jacketing integrity***
- Loss of Material
- Loss of Material (Spalling, Scaling) and Cracking
- Loss of Preload
- Loss of Sealing

#### Aging Management Programs

The following aging management programs manage the aging effects for the Structural Commodity Group components:

- Boric Acid Corrosion (B.2.1.4)
- ***External Surfaces Monitoring of Mechanical Components (B.2.1.23)***
- Structures Monitoring (B.2.1.34)

As a result of the responses to RAIs 3.2.2-1 and 3.5.2-1 provided in Enclosure A of this letter, LRA Table 3.5.2-3, Component Supports Commodity Group, pages 3.5-108, 3.5-121, and 3.5-130, is revised as shown below. Additions are indicated with ***bolded italics***.

**Table 3.5.2-3 Component Supports Commodity Group (Continued)**

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Supports for ASME Class 1 piping and components (Sliding Surfaces – NSSS component supports) | Structural Support | Graphitic Tool Steel | Air with Borated Water Leakage | Loss of Material | Boric Acid Corrosion (B.2.1.4) | III.B1.1.T-25 | 3.5.1-89 | A |
| | | | | | ***ASME Section XI, Subsection IWF (B.2.1.31)*** | ***III.B1.1.T-24*** | ***3.5.1-91*** | ***D*** |
| Supports for Emergency Diesel Generator, HVAC System Components, and Other Misc. Mechanical Equipment (Support members; welds; bolted connections; support anchorage to building structure) | Structural Support | Stainless Steel Bolting | Air - Indoor Uncontrolled | Loss of Preload | Structures Monitoring (B.2.1.34) | III.B4.TP-261 | 3.5.1-88 | A |
| | | | Air with Borated Water Leakage | Loss of Preload | Structures Monitoring (B.2.1.34) | III.B4.TP-261 | 3.5.1-88 | A |
| | | | Raw Water (Byron Only) | ***Loss of Material*** | ***Structures Monitoring (B.2.1.34)*** | | | ***G, 7*** |
| | | | | Loss of Preload | Structures Monitoring (B.2.1.34) | VII.I.AP-264 | 3.3.1-15 | E, 5 |

**Plant Specific Notes: (continued)**

***7. The Structures Monitoring (B.2.1.34) program is used to manage the loss of material aging effect applicable to this component type, material, and environment combination***

As a result of the responses to RAIs RAI 3.2.2-1, 3.5.2-2, 3.5.2-3 and 3.5.2-4 provided in Enclosure A of this letter, LRA Table 3.5.2-15, Structural Commodity Group, pages 3.5-247 through 3.5-252, 3.5-262, and 3.5-263, is revised as shown below. Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

**Table 3.5.2-15 Structural Commodity Group (Continued)**

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Bolting (Structural) | Structural Support | Carbon and Low Alloy Steel Bolting | Air with Borated Water Leakage | Loss of Material | Boric Acid Corrosion (B.2.1.4) | III.B5.T-25 | 3.5.1-89 | A |
| | | | | | ***Structures Monitoring (B.2.1.34)*** | ***III.B5.TP-248*** | ***3.5.1-80*** | ***A*** |

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Conduit | Shelter, Protection | Aluminum | Air - Indoor Uncontrolled | None | None | III.B2.TP-8 | 3.5.1-95 | C |
| | | Galvanized Steel | Air - Indoor Uncontrolled | None | None | III.B2.TP-8 | 3.5.1-95 | C |
| | | | Air - Outdoor | Loss of Material | Structures Monitoring (B.2.1.34) | III.B2.TP-6 | 3.5.1-93 | C |
| | | | Air with Borated Water Leakage | Loss of Material | Boric Acid Corrosion (B.2.1.4) | III.B2.TP-3 | 3.5.1-89 | C |
| | | | Groundwater/Soil | Loss of Material | Structures Monitoring (B.2.1.34) | III.A3.TP-219 | 3.5.1-79 | C |
| | | PVC | Air - Indoor Uncontrolled | None | None | VII.J.AP-268 | 3.3.1-119 | C |
| | | | ~~Groundwater/Soil~~ | ~~None~~ | ~~None~~ | | | ~~J, 1~~ |
| | | Polymers | Air - Indoor Uncontrolled | ~~None~~ ***Change in Material Properties*** | ~~None~~ ***Structures Monitoring (B.2.1.34)*** | | | J, 2 |
| | | | Air with Borated Water Leakage | Change in Material Properties | Structures Monitoring (B.2.1.34) | | | J, 3 |

**Table 3.5.2-15 Structural Commodity Group (Continued)**

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Conduit | Structural Support | Aluminum | Air - Indoor Uncontrolled | None | None | III.B2.TP-8 | 3.5.1-95 | C |
| | | Galvanized Steel | Air - Indoor Uncontrolled | None | None | III.B2.TP-8 | 3.5.1-95 | C |
| | | | Air - Outdoor | Loss of Material | Structures Monitoring (B.2.1.34) | III.B2.TP-6 | 3.5.1-93 | C |
| | | | Air with Borated Water Leakage | Loss of Material | Boric Acid Corrosion (B.2.1.4) | III.B2.TP-3 | 3.5.1-89 | C |
| | | | Groundwater/Soil | Loss of Material | Structures Monitoring (B.2.1.34) | III.A3.TP-219 | 3.5.1-79 | C |
| | | PVC | Air - Indoor Uncontrolled | None | None | VII.J.AP-268 | 3.3.1-119 | C |
| | | | ~~Groundwater/Soil~~ | ~~None~~ | ~~None~~ | | | ~~J, 1~~ |
| | | Polymers | Air - Indoor Uncontrolled | ~~None~~ ***Change in Material Properties*** | ~~None~~ ***Structures Monitoring (B.2.1.34)*** | | | J, 2 |
| | | | Air with Borated Water Leakage | Change in Material Properties | Structures Monitoring (B.2.1.34) | | | J, 3 |

**Table 3.5.2-15** **Structural Commodity Group** **(Continued)**

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Insulation | Thermal Insulation | Calcium Silicate | Air - Indoor Uncontrolled | None | None | ***VIII.I.S-403*** | ***3.4.1-64*** | ~~J~~ ***I***, 4 |
| | | | Air with Borated Water Leakage | None | None | ***VIII.I.S-403*** | ***3.4.1-64*** | ~~J~~ ***I***, 4 |
| | | Ceramic Fiber | Air - Indoor Uncontrolled | None | None | ***VIII.I.S-403*** | ***3.4.1-64*** | ~~J~~ ***I***, 4 |
| | | Fiberglass | Air - Indoor Uncontrolled | None | None | ***VIII.I.S-403*** | ***3.4.1-64*** | ~~J~~ ***I***, 4 |
| | | | Air with Borated Water Leakage | None | None | ***VIII.I.S-403*** | ***3.4.1-64*** | ~~J~~ ***I***, 4 |
| | | Foamed Plastic | Air - Indoor Uncontrolled | None | None | ***VIII.I.S-404*** | ***3.4.1-65*** | ~~J~~ ***I***, 4 |
| | | | Air with Borated Water Leakage | None | None | ***VIII.I.S-404*** | ***3.4.1-65*** | ~~J~~ ***I***, 4 |
| | | Mineral Fiber | Air with Borated Water Leakage | None | None | ***VIII.I.S-403*** | ***3.4.1-64*** | ~~J~~ ***I***, 4 |

**Table 3.5.2-15 Structural Commodity Group (Continued)**

| Component Type | Intended Function | Material | Environment | Aging Effect Requiring Management | Aging Management Programs | NUREG-1801 Item | Table 1 Item | Notes |
|---|---|---|---|---|---|---|---|---|
| Insulation Jacketing | Thermal Insulation Jacket Integrity | Aluminum | Air - Indoor Uncontrolled | ***Loss of thermal insulation jacketing integrity*** ~~None~~ | ***External Surfaces (B.2.1.23)*** ~~None~~ | ~~III.B5.TP-8~~ | ~~3.5.1-95~~ | ***H, 10*** ~~C~~ |
| | | | Air with Borated Water Leakage | Loss of Material | Boric Acid Corrosion (B.2.1.4) | III.B5.TP-3 | 3.5.1-89 | C |
| | | | | ***Loss of thermal insulation jacketing integrity*** | ***External Surfaces (B.2.1.23)*** | | | ***H, 10*** |
| | | Galvanized Steel | Air - Indoor Uncontrolled | ***Loss of thermal insulation jacketing integrity*** ~~None~~ | ***External Surfaces (B.2.1.23)*** ~~None~~ | ~~III.B5.TP-8~~ | ~~3.5.1-95~~ | ***H, 10*** ~~C~~ |
| | | | Air with Borated Water Leakage | Loss of Material | Boric Acid Corrosion (B.2.1.4) | III.B5.TP-3 | 3.5.1-89 | C |
| | | | | ***Loss of thermal insulation jacketing integrity*** | ***External Surfaces (B.2.1.23)*** | | | ***H, 10*** |
| | | Stainless Steel | Air - Indoor Uncontrolled | ***Loss of thermal insulation jacketing integrity*** ~~None~~ | ***External Surfaces (B.2.1.23)*** ~~None~~ | ~~III.B5.TP-8~~ | ~~3.5.1-95~~ | ***H, 10*** ~~C~~ |
| | | | Air with Borated Water Leakage | ***Loss of thermal insulation jacketing integrity*** ~~None~~ | ***External Surfaces (B.2.1.23)*** ~~None~~ | ~~III.B5.TP-4~~ | ~~3.5.1-95~~ | ***H, 10*** ~~C~~ |

**Plant Specific Notes:**

~~1.~~ ***Not Used.*** ~~This material and environment applies to PVC conduit in groundwater/soil environment. Based on plant operating experience, there are no aging effects requiring management for the combination of this material and environment. The material in this environment is not expected to experience significant aging effects.~~

**Table 3.5.2-15 Structural Commodity Group (Continued)**

**Plant Specific Notes (Continued):**

2. This material and environment applies to the vinyl covering on flexible, liquid-tight conduit in air – indoor environment. ~~Based on plant operating experience, there are no aging effects requiring management for the combination of these materials and environments. The material in this environment is not expected to experience significant aging effects.~~ ***The Structures Monitoring (B.2.1.34) program will be used to manage the polymer vinyl covering on the flexible, liquid-tight conduit.***

4. ***Plant specific operating*** ~~Operating~~ experience has shown the air-indoor uncontrolled and air with borated water leakage environments to contain insignificant quantities of moisture, humidity, condensation, and contaminants during normal operation. ***Insulation within the scope of license renewal is covered by water resistant jacketing. Plant-specific configuration control procedures will ensure that jacketing is properly installed so as to prevent water intrusion into the insulation (e.g., seams on the bottom, overlapping seams). Therefore, reduced thermal insulation resistance due to moisture intrusion is not an applicable aging effect for thermal insulation within the scope of license renewal as long as the integrity of the jacketing is maintained. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) is used to manage the potential aging effects associated with corrosion under insulation and to ensure that the integrity of thermal insulation jacketing is maintained.*** ~~Therefore, there are no aging effects associated with the insulation material in the normally dry, air - indoor uncontrolled and air with borated water leakage environments.~~

***10. Loss of thermal insulation jacketing integrity is an applicable aging effect for this component type. The External Surfaces Monitoring of Mechanical Components (B.2.1.23) aging management program includes periodic visual inspections to ensure that the integrity of thermal insulation jacketing is maintained such that moisture intrusion is prevented.***

As a result of the response to RAI 4.7.8-1 provided in Enclosure A of this letter, LRA Table 4.3.1-1 on page 4.3-5 is revised as follows:

Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

**Table 4.3.1-1 Byron Station, Units 1 and 2: Baseline and 60-Year Cycle Projections for RCS Transients**

| Transient Number and Description | Byron Station, Unit 1 | | Byron Station, Unit 2 | | CLB Cycle Limit (2) |
|---|---|---|---|---|---|
| | Baseline Cycles (1) | Projected Cycles | Baseline Cycles (1) | Projected Cycles | |
| 17. Reactor Coolant Pump Startup/Shutdown | 1,065 | 1,755 | 960 | 1,545 | 3,000 (19) |
| 18. RCS Venting | N/A | N/A | N/A | N/A | 320 (14) |
| 19. Economic Generation Control | N/A | N/A | N/A | N/A | 26,280 (15) |
| **Upset Condition RCS Transients** | | | | | |
| 20. Loss of Load | 3 | 6 | 1 | 4 | 80 |
| 21. Loss of Power | 2 | 4 | 3 | 5 | 40 |
| 22. Partial Loss of Flow | 0 | 3 | 0 | 3 | 80 |
| 23. Reactor Trip from Full Power: Case A – with no inadvertent cooldown | 23 | 31 | 19 | 28 | 230 |
| 24. Reactor Trip from Full Power: Case B – with cooldown and no safety injection | 32 | 38 | 18 | 24 | 160 |
| 25. Reactor Trip from Full Power: Case C – with cooldown and safety injection | 1 | 2 | 1 | 2 | 10 |
| 26. Inadvertent RCS Depressurization | 1 | 2 | 0 | 1 | 20 |
| 27. Inadvertent Startup of Inactive Loop | N/A | N/A | N/A | N/A | 10 (12) |
| 28. Control Rod Drop | 8 | 11 | 3 | 6 | 80 |
| 29. Inadvertent Safety Injection (ECCS) Actuation | 6 | 8 | 7 | 9 | 60 |
| 30. Excessive Feedwater Flow | 1 | 2 | 0 | 2 | 30 |
| 31. Bypass Line Tempering Valve Failure | 0 | 2 | 0 | 2 | 20 (16) |
| 32. Excessive Bypass Feedwater Flow | 0 | 2 | 0 | 2 | ~~40~~ ***30*** |

As a result of the response to RAI 4.7.8-1 provided in Enclosure A of this letter, LRA Table 4.3.1-4 on page 4.3-14 is revised as follows:

Additions are indicated with ***bolded italics***; deletions are shown with ~~strikethroughs~~.

**Table 4.3.1-4 Braidwood Station, Unit 1 and Unit 2: Baseline and 60-Year Cycle Projection for RCS Transients**

| Transient Number and Description | Braidwood Station, Unit 1 | | Braidwood Station, Unit 2 | | CLB Cycle Limit (2) |
|---|---|---|---|---|---|
| | Baseline Cycles (1) | Projected Cycles | Baseline Cycles (1) | Projected Cycles | |
| 18. RCS Venting | N/A | N/A | N/A | N/A | 320 (14) |
| 19. Economic Generation Control | N/A | N/A | N/A | N/A | 26,280 (15) |
| **Upset Condition RCS Transients** | | | | | |
| 20. Loss of Load | 1 | 4 | 1 | 6 | 80 |
| 21. Loss of Power | 1 | 3 | 3 | 6 | 40 |
| 22. Partial Loss of Flow | 2 | 5 | 1 | 6 | 80 |
| 23. Reactor Trip from Full Power: Case A – with no inadvertent cooldown | 11 | 18 | 38 | 51 | 230 |
| 24. Reactor Trip from Full Power: Case B – with cooldown and no safety injection | 11 | 16 | 9 | 18 | 160 |
| 25. Reactor Trip from Full Power: Case C – with cooldown and safety injection | 4 | 5 | 1 | 2 | 10 |
| 26. Inadvertent RCS Depressurization | 1 | 2 | 0 | 2 | 20 |
| 27. Inadvertent Startup of Inactive Loop | N/A | N/A | N/A | N/A | 10 (12) |
| 28. Control Rod Drop | 4 | 7 | 6 | 11 | 80 |
| 29. Inadvertent Safety Injection (ECCS) Actuation | 0 | 2 | 0 | 4 | 60 |
| 30. Excessive Feedwater Flow | 0 | 2 | 0 | 2 | 30 |
| 31. Bypass Line Tempering Valve Failure | 0 | 2 | 0 | 2 | 20 (16) |
| 32. Excessive Bypass Feedwater Flow | 0 | 2 | 0 | 2 | ~~40~~ ***30*** |
| 33. RCS Cold Overpressurization Transient | 1 | 2 | 0 | 1 | 10 |

As a result of changes to the Closed Treated Water Systems aging management program identified in the response to RAI B.2.1.12-1, the first paragraph of LRA Appendix A, Section A.2.1.12, page A-18, is revised as shown below. Changes are highlighted with ***bolded italics*** for inserted text.

### A.2.1.12 Closed Treated Water Systems

The Closed Treated Water Systems program is an existing mitigative and condition monitoring program that includes (a) nitrite-based and glycol-based water treatment, including pH control and the use of corrosion inhibitors, to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of corrosion and/or cracking. ***The inspections include opportunistic inspections whenever the system boundary is opened as well as new periodic inspections described in Enhancement 1.*** The Closed Treated Water Systems program manages the loss of material, the reduction of heat transfer, and cracking in piping, piping components, piping elements, tanks, and heat exchangers.

The Closed Treated Water Systems aging management program will be enhanced to:

1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control at mitigating aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, fouling, or cracking and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical.

2. Perform periodic sampling, analysis, and trending of water chemistry for the essential service water makeup pump engine glycol-based jacket water system to verify the effectiveness of water chemistry control at mitigating aging effects (Byron only).

These enhancements will be implemented prior to the period of extended operation.

As a result of the response to RAI 3.5.2-4 provided in Enclosure A of this letter, LRA Appendix A, Section A.2.1.23, page A-28, is revised as shown below. This section was previously revised as a result of the responses to RAIs 3.0.3-3 and B.2.1.23-1 provided in Exelon letter RS-14-003, dated January 13, 2014. Pre-existing text, from the LRA or previous RAI responses, is formatted in normal font. 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. ***The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation.***

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 response to RAI 3.1.2-1 provided in Enclosure A of this letter, the Program Description sub-section of LRA Appendix B.2.1.9, Bolting Integrity, on page B-67, is revised as shown below. Additions are indicated with ***bolded italics.***

### B.2.1.9 Bolting Integrity

#### Program Description

The Bolting Integrity aging management program is an existing condition monitoring program. The program provides for aging management for loss of preload, cracking, and loss of material due to corrosion of closure bolting on pressure retaining joints within the scope of license renewal. The program includes closure bolting on pressure retaining joints in indoor air, outdoor air, air with borated water leakage, condensation, raw water, and soil. The Bolting Integrity program incorporates NRC and industry recommendations delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance & Applications Guide," and EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants."

The program generally includes periodic inspection of closure bolting, at least once per refueling cycle, for indications of loss of preload, cracking, and loss of material. The program credits visual inspection of pressure retaining bolted joints in ASME Class 1, 2, and 3 systems for leakage and age-related degradation during system pressure tests performed in accordance with ASME Section XI, 2001 Edition through the 2003 Addenda. In addition, the Bolting Integrity aging management program credits volumetric, surface, and visual inspections of ASME Class 1, 2, and 3 bolts, nuts, washers, and other associated bolting components performed in accordance with ASME Section XI, Subsections IWB, IWC, and IWD. The integrity of non-ASME (nonsafety-related) pressure retaining bolted joints (in non-ASME Class 1, 2, 3 and MC systems) is monitored by detection of visible leakage, evidence of past leakage, or other age-related degradation during maintenance activities and walkdowns in plant areas that contain systems within scope of license renewal. ***This program also includes visual inspections for loose or missing nuts and bolts and other conditions indicative of loss of preload and rust, corrosion byproducts, or other conditions indicative of loss of material.*** Inspection activities of closure bolting on pressure retaining joints within the scope of license renewal in submerged environments will be performed in conjunction with associated component maintenance activities. These monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant age-related degradation.

As a result of changes to the Closed Treated Water Systems aging management program identified in the response to RAI B.2.1.12-1, the first paragraph of LRA Appendix B, Section B.2.1.12, page B-89, is revised as shown below. Changes are highlighted with ***bolded italics*** for inserted text.

## B.2.1.12 Closed Treated Water Systems

### Program Description

The Closed Treated Water Systems program is an existing mitigative and condition monitoring program that includes (a) nitrite-based and glycol-based water treatment, including pH control and the use of corrosion inhibitors for aluminum, carbon steel, carbon steel lined with nickel alloy cladding, and copper alloys, ductile cast iron, gray cast iron, and stainless steel to modify the chemical composition of the water such that the function of the equipment is maintained and such that the effects of corrosion are minimized; (b) chemical testing of the water to ensure that the water treatment program maintains the water chemistry within acceptable guidelines; and (c) inspections to determine the presence or extent of corrosion and/or cracking. ***The inspections include opportunistic inspections whenever the system boundary is opened as well as new periodic inspections described in Enhancement 1.*** The Closed Treated Water Systems program manages the loss of material, the reduction of heat transfer, and cracking in piping, piping components, piping elements, tanks, and heat exchangers exposed to a closed treated water environment.

The Closed Treated Water Systems program is a mitigative program which also provides condition monitoring activities that are implemented through station procedures. Mitigative activities include utilizing nitrite-based and glycol-based chemistry controls to minimize the age-related degradation of components exposed to a closed treated water environment. The performance of sample analyses assures water chemistry parameters are maintained within the goal ranges specified by procedure and based on EPRI 1007820, Closed Cooling Water Chemistry Guideline. Monitoring of water chemistry parameters also assures contaminants are kept below applicable limits to prevent or limit corrosion. Condition monitoring activities provide for opportunistic visual inspections and nondestructive examinations which are effective in detecting applicable aging effects, and the frequency of monitoring is adequate to prevent significant age-related degradation.

The Closed Treated Water Systems program is also utilized to verify the effectiveness of the Water Chemistry (B.2.1.2) program in managing cracking due to stress corrosion cracking and cyclic loading for stainless steel non-regenerative heat exchangers exposed to treated borated water greater than 140 degrees Fahrenheit in the Chemical & Volume Control System. The Closed Treated Water Systems program provides for temperature and radioactivity monitoring of the shell side water of the non-regenerative heat exchangers.

The program will be enhanced, as noted below, to provide reasonable assurance that the Closed Treated Water Systems program aging effects of loss of material, reduction of heat transfer, and cracking will be managed during the period of extended operation.

**NUREG-1801 Consistency**

The Closed Treated Water Systems aging management program will be consistent with the ten elements of aging management program XI.M21A, “Closed Treated Water Systems,” specified in NUREG-1801.

**Exceptions to NUREG-1801**

None.

**Enhancements**

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

1. Perform condition monitoring, including periodic visual inspections and non-destructive examinations, to verify the effectiveness of water chemistry control at mitigating aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion, fouling, or cracking and inspected at an interval not to exceed once in 10 years during the period of extended operation. The selection of components to be inspected will focus on locations which are most susceptible to age-related degradation, where practical. **Program Elements Affected: Parameters Monitored or Inspected (Element 3), Detection of Aging Effects (Element 4)**

2. Perform periodic sampling, analysis, and trending of water chemistry for the essential service water makeup pump engine glycol-based jacket water system to verify the effectiveness of water chemistry control at mitigating aging effects (Byron only). **Program Elements Affected: Scope of Program (Element 1), Preventive Actions (Element 2), Parameters Monitored or Inspected (Element 3), Monitoring and Trending (Element 5)**

As a result of the response to RAI 3.5.2-4 provided in Enclosure A of this letter, the first paragraph of LRA Appendix B, Section B.2.1.23, page B-147, is revised as shown below. This section was revised as a result of the responses to RAI's 3.0.3-3 and B.2.1.23-1 provided in Exelon letter RS-14-003, dated January 13, 2014. Pre-existing text, from the LRA or previous RAI responses, is formatted in normal font. 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. ***The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. Insulation and jacketing is inspected, repaired, and installed in accordance with plant-specific procedures and specifications that include configuration features such as minimum overlap, location of seams, etc. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation.***

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.

# Enclosure C

## Byron and Braidwood Stations (BBS) Units 1 and 2
## License Renewal Commitment List Changes

This Enclosure identifies commitments made or revised 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:

RAI 3.5.2-4

Notes:

- To facilitate understanding, portions of the original License Renewal Commitment List have been repeated in this Enclosure, with revisions indicated.
- Pre-existing text, from the LRA or previous RAI responses, is formatted in normal font. Additions are indicated with ***bolded italics***.

As a result of the response to RAI 3.5.2-4 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. This section was previously revised as a result of the responses to RAIs 3.0.3-3 and B.2.1.23-1 provided in Exelon letter RS-14-003, dated January 13, 2014. Pre-existing text, from the LRA or previous RAI packages, is formatted in normal font. 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. ***The periodic system walkdowns include visual inspection of insulation jacketing to ensure the integrity of the jacketing is maintained. External visual inspections of the jacketing ensure that there is no damage to the jacketing that would permit in-leakage of moisture. The procedures for planning insulation repairs will be revised to document that insulation repairs are performed in accordance with specification requirements (e.g., seams on the bottom, overlapping seams) so as to prevent water intrusion into the insulation.*** 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.<br><br>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<br><br>Exelon letter RS-14-003 1/13/2014<br><br>RAI 2.1.23-1<br>RAI 3.0.3-3<br><br>***Exelon letter RS-14-051 2/27/2014***<br><br>***RAI 3.5.2-4*** |