LimerickNPEm Resource

From: Christopher.Wilson2@exeloncorp.com
Sent: Thursday, February 16, 2012 8:23 AM
To: Kuntz, Robert
Subject: Response letter
Attachments: Response To NRC Request dated 01-17-12 1.pdf

Rob

This letter was transmitted to DCC yesterday. I tried to send it to you but thee file size was too large. So I made this info only copy just fyi

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Hearing Identifier: Limerick_LR_NonPublic
Email Number: 1008

Mail Envelope Properties (9A15F707EB47A04D882D9FEB352EDDF803AD23AB)

Subject: Response letter
Sent Date: 2/16/2012 8:22:31 AM
Received Date: 2/16/2012 8:22:35 AM
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Recipients:
"Kuntz, Robert" <Robert.Kuntz@nrc.gov>
Tracking Status: None

Post Office: cccmsxch12.energy.power.corp

Files	**Size**	**Date & Time**
MESSAGE	1125	2/16/2012 8:22:35 AM
Response To NRC Request dated 01-17-12 1.pdf		383793

Options
Priority: Standard
Return Notification: No
Reply Requested: No
Sensitivity: Normal
Expiration Date:
Recipients Received:

10 CFR 50
10 CFR 51
10 CFR 54

February 15, 2012

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

Limerick Generating Station, Units 1 and 2
Facility Operating License Nos. NPF-39 and NPF-85
NRC Docket Nos. 50-352 and 50-353

Subject: Response to NRC Request for Additional Information, dated January 17, 2012, related to the Limerick Generating Station License Renewal Application

Reference: 1. Exelon Generation Company, LLC letter from Michael P. Gallagher to NRC Document Control Desk, "Application for Renewed Operating Licenses", dated June 22, 2011
2. Letter from Robert F. Kuntz (NRC) to Michael P. Gallagher (Exelon), "Requests for Additional Information for the review of the Limerick Generating Station License Renewal Application (TAC Nos. ME6555, ME6556)", dated January 17, 2012

In the Reference 1 letter, Exelon Generation Company, LLC (Exelon) submitted the License Renewal Application (LRA) for the Limerick Generating Station, Units 1 and 2 (LGS). In the Reference 2 letter, the NRC requested additional information to support the staffs' review of the LRA. Enclosed are the responses to these requests for additional information.

Changes to commitments are identified within Enclosure C.

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 02-15-2012

Respectfully,

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

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

cc: Regional Administrator – NRC Region I
NRC Project Manager (Safety Review), NRR-DLR
NRC Project Manager (Environmental Review), NRR-DLR
NRC Project Manager, NRR-Limerick Generating Station
NRC Senior Resident Inspector, Limerick Generating Station
R. R. Janati, Commonwealth of Pennsylvania

Enclosure A

Responses to Request for Additional Information related to various sections of the LGS License Renewal Application (LRA)

RAI 3.0.2-1
RAI 3.1.2.3-1
RAI 3.4.2.7-1
RAI BWRVIP-1
RAI B.2.1.2-1
RAI B.2.1.3-1
RAI B.2.1.7-2
RAI B.2.1.7-3
RAI B.2.1.11-1
RAI B.2.1.11-2
RAI B.2.1.12-1
RAI B.2.1.12-2
RAI B.2.1.13-1
RAI B.2.1.13-2
RAI B.2.1.15-1
RAI B.2.1.15-2
RAI B.2.1.17-1
RAI B.2.1.17-2
RAI B.2.1.17-3
RAI B.2.1.19-1
RAI B.2.1.19-2
RAI B.2.1.20-1
RAI B.2.1.23-1
RAI B.2.1.25-1
RAI B.2.1.26-1
RAI B.2.1.26-2
RAI B.2.1.29-1
RAI B.2.1.29-2
RAI B.2.1.29-3

RAI 3.0.2-1

Background

License renewal application (LRA) Table 3.0-2 states that the air-indoor, uncontrolled environment encompasses the Generic Aging Lessons Learned (GALL) Report defined environments of “air-indoor uncontrolled,” “air-indoor uncontrolled (>95 °F),” “air with steam or water leakage,” “air with leaking secondary-side water and/or steam,” and “condensation.” LRA Table 3.0-2 also states that, for the air-indoor, uncontrolled environment, humidity levels of up to 100 percent are assumed, surfaces of components may be wet, and the environment may contain aggressive chemical species.

Issue

The staff identified a number of aging management review (AMR) items for which there are no specified aging effects when exposed to “air- indoor, uncontrolled.” However, the staff also identified that these same AMR items would have aging effects if they were exposed to “condensation,” as defined by the GALL Report. It is unclear to the staff if the components with an environment of air-indoor, uncontrolled are exposed to potentially adverse environments. Without this information, the staff cannot evaluate whether the proper aging effects and aging management programs are being applied to manage components for which the environment is listed as air-indoor, uncontrolled.

Request

Identify which AMR items in the LRA are exposed to an air-indoor, uncontrolled environment for which humidity, condensation, moisture, or contaminants are present. If in identifying these items it is determined that there are aging effects requiring management, propose an aging management program (AMP) to manage the aging effect or state the basis for why no AMP is required.

Exelon Response

The information presented in LRA Table 3.0-2 included potentially acceptable LGS/GALL environment correlations that may be utilized if justified. This table should instead have listed only the environment correlations that were actually used.

For the LGS "Air-Indoor, Uncontrolled" environment described in LRA Table 3.0-2, the only GALL environments that were utilized were "Air - indoor, uncontrolled" and "System temperature up to 288°C (550°F)" (for closure bolting). Any environments that had the potential for moisture or condensation to form were identified as "Air/Gas - Wetted". As described in LRA Table 3.0-1, the LGS "Air/Gas - Wetted" environment corresponds to the "Condensation" and "Air, moist" GALL environments. Any environments that had the potential for contaminants would have been identified as "Air - Outdoor" or "Air with steam or water leakage". As described in LRA Table 3.0-2, the LGS "Air - Outdoor" environment corresponds to the "Air - outdoor" GALL environment. The "Air with steam or water leakage" environment was not applicable for LGS.

There are no AMR line items in the LRA for which the environment of air-indoor, uncontrolled contains humidity, condensation, moisture or contaminants. Therefore, there are no additional aging effects requiring management. The air environments which have the potential for humidity, condensation, moisture or contaminants have been identified as air/gas - wetted or air

- outdoor; and correspond to the GALL environments of condensation or moist air, and air - outdoor respectively.

LRA Table 3.0-2 has been revised to reflect the actual GALL environment that was aligned with the LGS "Air - Indoor, Uncontrolled" environment. The description of the LGS "Air - Indoor, Uncontrolled" environment has been revised to definitively state that the surfaces exposed to this environment are normally dry.

An extent of condition review was performed on all LGS environments listed in LRA Tables 3.0-1 (for internal environments) and 3.0-2 (for external environments), and both tables have been updated to reflect the actual LGS/GALL environment correlations that were utilized, and to clarify definitions as appropriate. In addition, the text of LRA section 3.0 was amended to clarify that LGS environments which were both internal and external environments were listed only on Table 3.0-1. This review did not identify any additional aging effects requiring management.

During evaluation of this RAI, it was determined that 5 AMR line items for aluminum components and 1 AMR line item for a galvanized steel component were correctly identified with an "Air - Indoor, Uncontrolled" environment, but the selected GALL line item corresponded to an "Air - Indoor, Controlled" environment. LRA Tables 3.2.2-6, 3.3.2-4, 3.3.2-9, and 3.3.2-16 have been amended to reference the correct GALL line item for the "Air - Indoor, Uncontrolled" environment. In addition, Table 3.2.1 item 59 has been updated to reflect this correction. There is no change to aging management programs as a result of this change.

LRA Section 3.0 and Tables 3.0-1, 3.0-2, 3.2.1, 3.2.2-6, 3.3.2-4, 3.3.2-9, and 3.3.2-16 are revised as shown in Enclosure B.

RAI 3.1.2.3-1

Background

In the LRA Table 3.1.2-03 (page 3.1-66), there is an AMR result for stainless steel (part of jet pump assembly) in a reactor coolant and neutron flux environment with an aging effect of loss of preload. The AMR results credit the Boiling Water Reactor Vessel Internals Program (BWRVIP) with managing the aging effect of loss of preload. The AMP uses BWRVIP-41, Revision 3 for the jet pump assembly, which outlines specific surface and volumetric inspections that look for evidence of cracking and wear, not loss of preload. Loss of preload is usually associated with bolts and in the reactor coolant and neutron flux environment is addressed as a TLAA as in LRA Section 4.6.9 in the jet pump slip joint repair clamps.

Issue

The LRA does not provide sufficient information for the staff to understand how the BWR Vessel Internals Program can effectively manage loss of preload for the jet pump assembly in a reactor coolant and neutron flux environment.

Request

1. Describe the specific stainless steel components in the jet pump assembly that are related to this AMR line item.

2. Explain what specific features or activities of the BWR Vessel Internals Program and BWRVIP-41, Revision 3 will manage the aging effect of loss of preload for the jet pump assembly that is in the reactor coolant and neutron flux environment.

Exelon Response

1. The jet pump slip joint repair clamps are the specific stainless steel components in the jet pump assembly that are related to the AMR result in LRA Table 3.1.2-3 for stainless steel (part of jet pump assembly) in a reactor coolant and neutron flux environment with an aging effect of loss of preload. This AMR result was included in LRA Table 3.1.2-3 to be consistent with the TLAA evaluation for the jet pump slip joint repair clamps as documented in LRA Section 4.6.9.
2. In the response to RAI 4.6.9-1, provided in letter, "Response to NRC Request of Additional Information, dated December 15, 2011, related to the Limerick Generating Station License Renewal Application", dated January 24, 2012, LRA Section 4.6.9, Jet Pump Slip Joint Repair Clamps, was revised to document that the fluence value used to determine loss of preload in the design analysis will not be exceeded during the period of extended operation. Therefore, periodic inspections of the jet pump slip joint repair clamps under the BWR Vessel Internals program are not credited to manage loss of preload. The response to RAI 4.6.9-1 included revision to LRA Table 3.1.2-3 to delete the aging management review line item for managing loss of preload of stainless steel jet pump assembly components by the BWR Vessel Internals program.

RAI 3.4.2.7-1

Background

The staff reviewed a sample of thirty-five component, material and environment combinations, selected from the LRA, during the audit conducted October 3–14, 2011. These components were randomly selected for the staff to verify the accuracy of the information provided in the AMR results in the applicant's LRA. The staff also performed walkdowns during the audit to determine whether the selected component, material and environment combinations, as listed in the LRA, were consistent with descriptions in the LRA.

Issue

The electro-hydraulic control (EHC) drain tank in the main turbine system (Table 3.4.2-7) is identified in the LRA as being constructed of stainless steel and exposed to an environment of air/gas-wetted (internal). The staff could not verify the EHC drain tank material during the walkdown or during a subsequent review of documentation provided by the applicant.

Request

Verify the material composition of the component described above and, if necessary, provide the results of an updated aging management review, in accordance with 10 CFR 54.21(a)(1).

Exelon Response

The electro-hydraulic control (EHC) tank is an in-line piping component (4 cubic foot surge chamber) installed in a piping system that is manufactured from stainless steel. This system was provided by the manufacturer of the LGS turbine generator. The manufacturer has provided information that confirms that the drain tank is fabricated from two stainless steel materials, Type 347 (Columbium stabilized chromium nickel steel) and Type 309S stainless steel. These materials are consistent with the stainless steel material selection for the aging management review identified in LRA Table 3.4.2-7. No update to the aging management review is required.

RAI BWRVIP-1

Background

The LRA references several BWRVIP reports, which have been reviewed and approved by the NRC staff, as part of its aging management programs. As part of the staff's approval of these BWRVIP reports and a condition for the use of these BWRVIP reports, the staff's safety evaluation (SE) identified license renewal applicant action items that are to be addressed by license renewal applicants in the LRA. As an example, BWRVIP-48-A is used by the BWR Vessel ID Attachment Welds Program that is described in LRA Section B.2.1.4 and the license renewal applicant action items are documented in Section 4.1 of the staff's SE, dated January 17, 2001.

Issue

The staff noted that the license renewal applicant action items discussed in the staff's SE dated January 17, 2001, were not discussed in the LRA. In addition, the license renewal applicant action items associated with any staff-reviewed and approved BWRVIP reports were not addressed in the LRA.

Request

Submit the necessary information and revisions to the LRA for each license renewal applicant action item in all applicable BWRVIP reports that are credited for aging management. If not, justify why the license renewal applicant action items do not need to be address in the LRA.

Exelon Response

A revision to the LRA to address each license renewal applicant action item in all applicable BWRVIP reports credited for aging management is provided as a new Appendix C of the LRA, as shown in Enclosure B. Review of BWRVIP-74-A LR Action Item 14 identified the need to identify a new license renewal commitment.

LRA Appendix A, Table A-5 is revised as shown in Enclosure C to include a commitment to re-evaluate the flaw in the Unit 1 RPV nozzle to safe-end weld VRR-1RD-1A-N2H in accordance with ASME Code Section XI, subsection IWB-3600 for the 60-year service period corresponding to the LR term.

RAI B.2.1.2-1

Background

SRP-LR, Table 3.0-1, “FSAR Supplement for Aging Management of Applicable Systems,” for GALL AMP XI.M2 states that the Water Chemistry program monitors and controls contaminants below the system-specific limits based on Electric Power Research Institute (EPRI) guidelines BWRVIP-190 for BWRs.

LRA Section A.2.1.2, Water Chemistry, states system-specific limits based on guidelines of EPRI but a reference to BWRVIP-190 is omitted.

Issue

The SRP-LR’s FSAR supplement for this program specifically references EPRI’s BWRVIP-190 which is omitted in the applicant’s FSAR supplement. The inclusion of the EPRI BWRVIP-190 guideline is necessary to ensure proper aging management of systems, structures and components through the period of extended operation.

Request

Revise LRA Section A.2.1.2 to reflect the appropriate references recommended for this program consistent with the SRP-LR’s FSAR supplement.

Exelon Response

LRA Section A.2.1.2 is revised to reflect the appropriate reference recommended for this program consistent with the SRP-LR’s FSAR supplement for program XI.M2, Water Chemistry, as shown in Enclosure B.

RAI B.2.1.3-1

Background

LRA Section B.2.1.3 states that the Reactor Head Closure Stud Bolting Program is consistent with the ten elements of aging management program XI.M3, "Reactor Head Closure Stud Bolting," specified in the GALL Report. The "preventive actions" program element of GALL Report, AMP XI.M3, "Reactor Head Closure Stud Bolting," references the guidance outlined in Regulatory Guide (RG) 1.65, "Materials and Inspections for Reactor Vessel Closure Studs," and NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants." The "preventive actions" program element of GALL Report AMP XI,M3 also lists preventive measures that can reduce the potential for stress corrosion cracking (SCC) or intergranular stress corrosion cracking (IGSCC), such as (1) using bolting material for closure studs that has an actual measured yield strength less than 150 ksi, and (2) using manganese phosphate or other acceptable surface treatments.

LRA Section B.2.1.3 states that the reactor head closure studs, nuts, bushings, flange threads, and washers are surface treated with an acceptable phosphate coating to inhibit corrosion and reduce SCC and IGSCC. By contrast, LGS UFSAR Section 5.3.1.11, states that a phosphate coating is applied to threaded areas of studs and nuts and bearing areas of nuts and washers.

It is not clear from the UFSAR description whether a phosphate coating is applied on the reactor vessel flange threads (as stated in the LRA). In addition, during its audit, the staff was not able to verify from applicant's on-site documents whether the applied coating for the closure bolting components is intact and effective in managing corrosion and SCC of the bolting components.

Issue

During its audit, the staff noted that the applicant's documents for its Reactor Head Closure Studs Bolting Program indicate that some of the closure studs and nuts are manufactured from material with actual measured yield strength greater than 150 ksi, which is not consistent with the recommendation in the GALL Report. The staff also needs clarification on whether a phosphate coating is applied on the flange threads so that a potential discrepancy between the LRA and UFSAR is resolved. In addition, the staff needs clarification on whether the coating on the closure bolting components is intact and is effective in managing corrosion and SCC of the bolting components, supporting the effectiveness of the coating for the period of extended operation.

Request

1. Clarify if closure studs and nuts manufactured from material with actual measured yield strength greater than 150 ksi will continue to be used in the period of extended operation. If they will be, revise LRA Section B.2.1.3 and associated UFSAR supplement to identify the use of closure stud bolting with actual measured yield strength greater than or equal to 150 ksi as an exception to GALL AMP XI.M3.

2. Justify why the aging management program is adequate to manage cracking due to stress corrosion cracking in the high-strength material. As part of the response, describe preventative actions to avoid exposure of the studs to the environments conducive to SCC.

3. Provide clarification for the potential discrepancy between the LRA and UFSAR and verify whether a phosphate coating is applied on the flange threads. In addition, state whether or not the coating applied to the closure bolting components is intact. If the flange threads do not have a coating and/or the coating on the closure bolting components have degraded, justify why the aging management program is adequate to manage corrosion.

Exelon Response

1. Reactor head closure studs and nuts manufactured from material with actual measured yield strength greater than 150 ksi will continue to be used during the period of extended operation. Certified Material Test Reports (CMTRs) obtained for the reactor head closure studs installed prior to commercial operation, and used as replacements, on Units 1 and 2 include test data indicating that all installed studs may have actual measured yield strength greater than 150 ksi. Each of the CMTRs obtained for heats used for the reactor head closure studs installed prior to commercial operation included at least one test result for certain bars where the measured yield strength was greater than 150 ksi. The CMTRs do not indicate which bar within the heat the studs were fabricated from.

CMTR Data for Reactor Head Closure Studs				
Heat	**Average Yield Strength**	**Maximum Yield Strength**	**Maximum Tensile Strength**	**Where Used**
89616	146.0 ksi	150.5 ksi	164 ksi	Unit 1 – All Studs, Unit 2 - 1 Stud
19626	144.0 ksi	150.5 ksi	165 ksi	Unit 2 - 69 Studs
83222	152.1 ksi	157.0 ksi	169 ksi	Unit 2 - 4 Studs
61923	148.9 ksi	152.7 ksi	167.34 ksi	Unit 2 - 2 Studs

Yield strength data is available only for Unit 2 reactor head closure nuts. The CMTR for one Unit 2 nut includes test results where the measured yield strength was greater than 150 ksi. The average measured yield strength for the heat used for that nut is 148.7 ksi. CMTR test results indicate that all the other Unit 2 nuts have yield strength less than 150 ksi. Since CMTR data is not available for Unit 1 nuts, they may also be fabricated from material having actual measured yield strength greater than 150 ksi.

CMTR Data for Reactor Head Closure Nuts				
Heat	**Average Yield Strength**	**Maximum Yield Strength**	**Maximum Tensile Strength**	**Where Used**
17501	141.8 ksi	143.25 ksi	157 ksi	Unit 2 - 75 Nuts
15009	148.7 ksi	153.0 ksi	165 ksi	Unit 2 - 1 Nut

LRA Section B.2.1.3 is revised to identify the use of closure studs with actual measured yield strength greater than or equal to 150 ksi as an exception to GALL Report AMP XI.M3 as shown in Enclosure B. The UFSAR Supplement Section A.2.1.3 is revised as shown in Enclosure B to identify the use of stud bolting material having measured yield strength greater than 150 ksi.

2. The reactor head closure studs are fabricated from SA 540 Grade B24 carbon steel, which has a minimum yield strength of 130 ksi. Relative to material strength, the studs are in compliance with Regulatory Guide (RG) 1.65 Revision 0 which required the studs to have a maximum measured tensile strength of 170 ksi. The maximum reported ultimate tensile strength for the installed studs is 164 ksi for Unit 1 and 169 ksi for Unit 2. RG 1.65 Revision 1 describes SA 540 Grade B24 as high-strength, low alloy material, that when tempered to a maximum tensile strength of less than 170 ksi is relatively immune to stress corrosion cracking. Therefore, the installed studs were consistent with the existing regulatory guidance when installed, and are relatively immune to stress corrosion cracking.

   CMTR data for the installed studs indicates that it is possible that all installed studs may have measured yield strength above 150 ksi, however the average measured yield strength for the heats used for all but four of the studs is less than 150 ksi. The average measured yield strength for the heat used for four Unit 2 studs is 152.1 ksi, with a maximum reported test result of 157 ksi. The CMTR data indicates that the installed studs have measured yield strength that is at most marginally above GALL Report AMP XI.M3 criteria.

   Other preventive measures listed in GALL Report AMP XI.M3, Element 2 that can reduce the potential for cracking are met as discussed below:

a) Metal-plated stud bolting is not used, which could cause degradation due to corrosion or hydrogen embrittlement;

b) A phosphate surface treatment was applied to the studs, nuts and washers during fabrication to inhibit corrosion;

c) An approved stable lubricant is applied to the studs and associated hardware whenever the reactor head is installed. The lubricant used does not contain molybdenum disulfide (MoS_2) which has been shown to be a potential contributor to cracking.

An additional preventive measure has been implemented to revise the purchasing requirements for RPV head studs to assure that any studs installed in the future have a measured yield strength less than 150 ksi as reported on CMTRs.

Since the actual measured yield strength of the installed studs may be greater than 150 ksi, the aging management review (LRA Table 3.1.2-2) identified the stud material as “High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater”. This resulted in identifying “Cracking” as an aging effect requiring management. The volumetric (UT) examination method in place for stud inspection per ASME Section XI, Table IWB-2500-1, Category B-G-1, and required per the Reactor Head Closure Stud Bolting aging management program, is appropriate for identifying cracking. To avoid exposure of the studs to an environment conducive to SCC, a system pressure test is performed prior to plant startup following each refueling outage in accordance with Table IWB-2500-1, Category B-P which results in identification and correction of any reactor coolant leakage at the reactor vessel head flange. There have been no recordable indications identified by Inservice Inspection program examination of reactor head closure stud bolting components over the past ten years indicating that the current program has been effective in managing cracking.

3. A manganese phosphate coating was applied to the threaded areas of the studs and nuts and bearing areas of the nuts and washers as described in the UFSAR. A phosphate coating was not applied to the flange threads. Based on recent observations by personnel that perform inspections of closure stud bolting components, there is no visual evidence that the coating is intact. This is expected since the coating is described as soft and when put into service smears between parts in contact with each other. Repeated disassembly, assembly, cleaning and lubrication is expected to wear the coating away. The coating is intended to be a rust inhibitor during storage prior to the component being placed in service and acts as a buffer to prevent galling during component break-in. RG 1.65 describes the application of a manganese phosphate coating on stud bolting components as an "acceptable surface treatment" that "may be used". Corrosion is managed effectively by the aging management program during the period of extended operation by the application of an approved, stable lubricant whenever the stud bolting is assembled and by periodic examination in accordance with ASME Code Section XI, Table IWB-2500-1, Category B-G-1. There have been no recordable indications identified by Inservice Inspection program examination of reactor head closure stud bolting components over the past ten years on both units. This indicates that the current program has been effective in managing corrosion.

   Review of this RAI resulted in identifying that the LGS design for reactor head closure stud bolting does not include bushings as described in LRA Section B.2.1.3 and UFSAR Supplement, Section A.2.1.3. LRA Section B.2.1.3 is revised to delete bushings and flange threads from the list of components that were fabricated with phosphate coating, and delete

bushings from the list of components managed by the program, as shown in Enclosure B. UFSAR Supplement Section A.2.1.3 is revised to delete bushings from the list of components managed by the program as shown in Enclosure B.

RAI B.2.1.7-2

Background

The "scope of program" program element of GALL Report, AMP XI.M7, "BWR Stress Corrosion Cracking," states that the program is applicable to all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93°C (200 ^{O}F) during power operation, regardless of code classification.

In comparison, LRA Section B.2.1.7 states that the BWR Stress Corrosion Cracking Program manages IGSCC in reactor coolant pressure boundary (RCPB) piping and piping components made of stainless steel and nickel-based alloy in a reactor coolant environment. In addition, LRA item 3.2.1-54 indicates that the GALL Report recommends the BWR Stress Corrosion Cracking to manage cracking due to SCC and IGSCC of stainless steel piping, piping components, and piping elements exposed to treated water >60°C (140°F). The staff also noted that LRA item 3.2.1-54 is for the engineered safety features. However, LRA Table 3.1.2-1 and related information in the LRA indicate that the applicant credited LRA item 3.2.1-54 to manage the aging effect of RCPB components only.

During the audit, the staff noted that the applicant's onsite documentation, including the weld selection table for inservice inspection, indicates that the BWR Stress Corrosion Cracking Program includes two ASME Code Class 2 welds associated with valves in the reactor water cleanup system (RWCU system) of LGS Unit 1 and that one of the welds is IGSCC Category B and the other weld is IGSCC Category C.

Issue

The LRA does not clearly address whether the scope of applicant's BWR Stress Corrosion Cracking Program includes piping and piping welds regardless of ASME Code classification, consistent with the GALL Report. The staff noted that the LRA includes the RCPB in the program scope; however, the LRA does not clearly address whether or not the scope of the program includes non-ASME Class-1 piping and its associated welds.

In addition, the staff noted that only RWCU system piping and piping welds outboard of the second containment isolation valves are included in the scope of GALL Report AMP XI.M25, while RWCU system piping and piping welds inboard of the second containment isolation valves are included in the BWR Stress Corrosion Program; therefore, the staff found a need to further clarify whether or not the LGS Unit 1 ASME Code Class 2 welds, categorized as IGSCC Category Band C, are located inboard of the second containment isolation valves.

Request

1. Describe whether or not the scope of the BWR Stress Corrosion Cracking Program includes BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of ASME Code classification, consistent with the GALL Report.

If the scope of the program does not include non-Class 1 piping and piping welds, justify why non-Class-1 piping and piping welds can be excluded from the program scope.

2. Revise LRA Section A.2.1.7 (the UFSAR supplement) to clarify that the scope of the program includes the relevant piping and piping welds regardless of code classification.

3. Clarify whether or not the Class 2 welds associated with the valves in the LGS Unit 1 RWCU system are located inboard of the second containment isolation valves (i.e., "inboard" valves),

   If these Class 2 welds are associated with "inboard" valves, clarify why the applicant's statement that the program manages the aging effect of the RCPB components is inconsistent with the inclusion of these Class 2 welds in the program.

Exelon Response

1. The BWR Stress Corrosion Cracking Program includes BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of ASME Code classification, consistent with the GALL Report. Determination of program scope included screening of all BWR piping and piping welds made of austenitic stainless steel that are four inches or greater in nominal diameter containing reactor coolant at a temperature greater than 93 ^{0}C (200 ^{0}F) during power operation, regardless of code classification. This screening identified only ASME Code Class 1 piping as within the scope of the BWR Stress Corrosion Cracking program.

2. The UFSAR Supplement LRA Section A.2.1.7 is revised to clarify that the scope of the BWR Stress Corrosion Cracking program includes relevant piping and piping welds regardless of code classification as shown in Enclosure B.

3. The two ASME Code Class 2 welds, discussed within the background and issue sections above and associated with valves in the LGS Unit 1 reactor water cleanup (RWCU) system, are located outboard of the second containment isolation valve. A Corrective Action Program Issue Report was created in August 2010 to identify that these two welds were incorrectly classified within the Inservice Inspection Program as requiring inspection as part of the USNRC GL 88-01 program. The procedure that contained the weld selection table for inservice inspection was not revised to correct the classification of these welds at the time of the audit. Since these two Class 2 welds are outboard of the second containment isolation valve, the statements made in LRA Section B.2.1.7 and UFSAR Supplement Section A.2.1.7 that the program manages cracking of the reactor coolant pressure boundary (RCPB) components are consistent with the scope of components managed by the program.

RAI B.2.1.7-3

Background

The "detection of aging effect" program element of GALL Report, AMP XI.M7, "BWR Stress Corrosion Cracking," states that the extent, method, and schedule of the inspection and test techniques delineated in NRC GL 88-01 or BWRVIP-75-A are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component. The GALL Report also states that modifications to the extent and schedule of inspection in NRC GL 88-01 are allowed in accordance with the inspection guidance in approved BWRVIP-75-A.

In comparison, LRA Section B.2.1.7 and onsite program basis document state that the inspection frequency for welds, classified as Category B through G per NRC GL 88-01, has been modified per the recommendations provided in the staff-approved BWRVIP-75-A, for normal water chemistry conditions. The LRA further states that welds classified as Category A have been subsumed into the Risk-Informed Inservice Inspection program in accordance with staff-approved EPRI Topical Report TR-112657, Revision B-A, Final Report, "Revised Risk Informed Inservice Inspection Evaluation Procedure," December 1999.

Issue

Although the applicant indicated that the program uses a staff-approved methodology described in EPRI TR-112657, Revision B-A to subsume IGSCC Category A welds in the risk-informed inservice inspection, the staff noted that the relief request was approved for the applicant's third 10-year inservice inspection interval, which is scheduled to end on January 31, 2017. The staff finds that the applicant should continue to get NRC approval for using this risk-informed method as an alternative to the ASME Code Section XI inservice inspection requirements for piping and the inspection requirements of GL 88-01.

Therefore, the staff finds a need to further clarify what extent, method and schedule the applicant would use to inspect the piping and piping components in the scope of the BWR Stress Corrosion Cracking Program in case the applicant could not continue to get NRC approval for using the risk-informed method described in EPRI TR-112657, Revision B-A. The staff also finds that the UFSAR supplement for this program should be further evaluated in terms of its consistency with the program on the use of the risk-informed method.

Request

1. Describe the extent, method and schedule that will be used to inspect the piping and piping components in the scope of the BWR Stress Corrosion Cracking Program in case the applicant could not continue to get NRC approval for using the risk-informed method described in EPRI TR-112657, Revision B-A.

2. Revise LRA Section A.2.1.7 (the UFSAR supplement), consistent with the response regarding the need for removing the reference to the risk-informed inservice inspection from the UFSAR supplement.

Exelon Response

1. In the event that NRC approval is not provided to use the risk-informed methodology described in EPRI TR-112657, Revision B-A for scheduling inspections for IGSCC Category A welds, the extent and schedule of the inspection and test techniques would be in accordance with the inspection guidance in approved BWRVIP-75-A. The inspection method is not affected by use of the risk-informed methodology and is in accordance with NRC GL 88-01 and NUREG-0313 Revision 2.

2. The UFSAR Supplement LRA Section A.2.1.7 is revised to be consistent with this response regarding the removal of the reference to risk-informed inservice inspection as shown in Enclosure B.

RAI B.2.1.11-1

Background

GALL Report AMP XI.M18, "Bolting Integrity," states that the program includes periodic inspections of closure bolting for loss of material, loss of preload, and cracking as well as preventive measures to minimize loss of preload and cracking. The "preventive actions" program element of GALL Report AMP XI.M18 states that the preventive measures to minimize cracking include not using lubricants that contain molybdenum disulfide and not using high strength bolting materials.

LRA Section B.2.1.11 states that the applicant's Bolting Integrity Program manages loss of material and loss of preload for pressure retaining bolts within the scope of license renewal. The LRA also states that high strength bolts are not used on pressure retaining bolted joints within the scope of the program and that station procedures ensure that lubricants containing molybdenum disulfide are not used. However, the program does not state that it manages cracking and does not include inspections for cracking.

Issue

It is unclear to the staff why cracking is not an aging effect requiring management by the applicant's Bolting Integrity Program, given that the preventive measures used in the program minimize the occurrence of cracking.

Request:

Clarify whether cracking is an aging effect being managed by the Bolting Integrity Program. If cracking is an aging effect being managed by the program, revise the LRA description of the program and the UFSAR supplement to include management of the aging effect. If cracking is not an aging effect being managed by the program, justify the exception to the GALL Report AMP.

Exelon Response

Cracking is an aging effect that is managed by the Bolting Integrity program. For safety-related bolting that does not meet the definition of high strength bolting in GALL Report AMP XI.M18,

visual inspections are performed once per refueling cycle. For other pressure retaining components, the bolted joints are inspected for signs of leakage that may result from cracking.

As described in LRA Sections A.2.1.11 and B.2.1.11, the Bolting Integrity program will be enhanced to minimize the use of high strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High strength bolting, if used, will be monitored for cracking.

Consistent with this response, the UFSAR Supplement for Bolting Integrity, A.2.1.11, and Bolting Integrity program description, B.2.1.11, are revised as shown in Enclosure B.

RAI B.2.1.11-2

Background

GALL Report AMP XI.M18, “Bolting Integrity,” states that bolting for safety-related pressure retaining components should be inspected for leakage as well as loss of material, cracking, and loss of preload.

LRA Section B.2.1.11 states that the program will manage loss of material and loss of preload using visual inspections for pressure-retaining bolted joint leakage. The LRA does not state that inspections will be performed for other indications of loss of material (such as corrosion or rust) cracking, or loss of preload (such as loose or missing bolts).

Issue

It is not clear to the staff whether the inspections performed by the Bolting Integrity Program will include inspections for indications of loss of material, cracking, and loss of preload other than just leakage.

Request

Clarify whether the inspections performed by the Bolting Integrity Program include inspections for other indications of loss of material, cracking, and loss of preload. If the inspections include other indications of loss of material, cracking, and loss of preload, revise the LRA description of the program and the UFSAR supplement to include this information. If the inspections are limited to leakage, justify the exception to the GALL Report AMP.

Exelon Response

The Bolting Integrity program provides for managing loss of material, cracking and loss of preload by performing visual inspections of pressure retaining bolted joints at least once per refueling cycle. These visual inspections of safety-related pressure retaining bolted joints not only identify leakage, but also identify loss of material, cracking, and loss of preload. Bolting for other pressure retaining bolted joints is inspected for signs of leakage.

The UFSAR Supplement in LRA Appendix A, Section A.2.1.11, and LRA Appendix B, Section B.2.1.11, are revised to clarify the attributes of the visual inspections consistent with GALL Report AMP XI.M18, Bolting Integrity, Element 3, "Parameters Monitored/Inspected". Revised pages are included in Enclosure B.

RAI B.2.1.12-1

Background

GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," relies on the implementation of recommendations in GL 89-13 and states that components exposed to raw water should be inspected for signs of corrosion, erosion, and biofouling. In addition, SRP-LR, Section A.1.2.3.10, "Operating Experience," states that past corrective actions for existing AMPs should be considered, and that feedback from past failures should have resulted in appropriate program enhancements.

LRA Section B.2.1.12, "Open-Cycle Cooling Water System," states that routine inspections and maintenance ensure that corrosion, erosion, and biofouling cannot degrade the performance of safety-related systems serviced by the open-cycle cooling water system. In addition, the LRA includes a program enhancement to perform internal inspections of buried safety-related service water piping whenever it is accessible during maintenance and repair activities.

The LRA's "Operating Experience" section for this AMP states that multiple leaks in the site's emergency service water (ESW) piping have been attributed to initial operation with untreated water that established significant corrosion cells. The LRA also states that although the current chemical treatment is appropriate, no chemical treatment is capable of reaching the active corrosion cells under the deposits of corrosion products, silt, and tubercles, and this has led to the replacement of susceptible portions of carbon steel piping with stainless steel. The operating experience section also discussed localized thinned areas in the residual heat removal service water (RHRSW) system, and concluded by stating that adequate corrective actions were taken to prevent recurrence for the problems identified.

During its onsite audit of the Open-Cycle Cooling Water System Program, the staff reviewed documents indicating that the historical corrosion issues in small and medium diameter raw water piping have more recently become evident in large diameter piping of the ESW and RHRSW systems. The staff also noted that the buried portions of these systems are typically among the largest diameter piping in the systems.

Issue

Based on the extent of degradation in the ESW and RHRSW systems, the staff lacks sufficient information to conclude that the Open-Cycle Cooling Water System Program will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. Due to the established, active corrosion cells, the existing carbon steel piping will continue to degrade, and although the current chemical treatment may prevent the establishment of new corrosion cells, it is unclear to the staff what enhancements were made to this AMP to address the consequences of past program weaknesses. Since additional leaks continue to be identified, it is unclear to the staff what specific corrective actions were taken to prevent recurrence of the identified problems.

In addition, discussions during the onsite audit indicated that portions of the associated aboveground piping were scheduled to be replaced and that future decisions regarding activities for buried piping would be based on information gathered from the removed piping. It is unclear to the staff whether these activities were only tentative or if any replacement activities could be definitively considered in the staff's evaluation of the program. Also, it is unclear to the staff whether the enhancement to perform opportunistic inspections of buried piping would be

adequate to maintain the systems' intended functions(s) during the period of extended operation, given the progression of through-wall leaks in large diameter ESW and RHRSW piping.

Request

1. For aboveground safety-related service water (ESW and RHRSW) piping that has not been replaced with stainless steel:

    a. State what augmented inspections are currently being performed, or planned to be performed, to identify loss of material before through-wall leakage occurs. Include the inspection method(s), frequency, number, location selection, and acceptance criteria. If these inspections have not been incorporated into the current program, then provide an enhancement with an associated commitment, or state the basis for why augmented inspections are not required.
    b. If current corrective actions include plans for replacing piping, then provide those aspects that can be credited in license renewal to alleviate ongoing degradation concerns or provide an enhancement, with an associated commitment, to reflect these aspects for the Open-Cycle Cooling Water System program. If corrective actions associated with piping replacement cannot be credited for license renewal, then provide the bases for the statement in the LRA that adequate corrective actions were taken to prevent recurrence for the problems identified.

2. For buried safety-related service water piping, provide technical bases to justify how opportunistic inspections will be capable of assessing its condition before loss of intended function occurs, or propose an alternate inspection approach to manage aging. If an alternate inspection approach is adopted, provide information on planned inspection activities, inspection techniques, frequency, location selection, acceptance criteria, and actions to be taken based on inspection findings to ensure that through-wall leaks of buried piping are not occurring. As appropriate, clarify Enhancement 1 associated with the Open-Cycle Cooling Water System program.

3. For both safety-related and in-scope nonsafety-related service water piping, provide a summary of analyses conducted in the past five years that evaluated the structural integrity of areas where degradation has caused pipe wall thicknesses to be less than nominal values. Include data to demonstrate that the degradation is limited to independent, localized corrosion sites or state how structural integrity has been evaluated for the potential of multiple adjacent corrosion sites that could have a cumulative adverse impact. If only independent localized corrosion sites have been discovered to date, state the basis for why multiple adjacent corrosion sites will not occur during the period of extended operation. In addition, provide a summary of any associated evaluations that considered system interactions such as flooding, spraying water on equipment, and loss of flow.

Exelon Response

1. Aboveground safety-related piping (ESW and RHRSW) is subject to an on-going inspection and piping replacement/upgrade program as described below:

    a. Inspections of the safety-related service water piping (ESW and RHRSW) are performed using ultrasonic examination (UT) and long range guided wave examinations. The Open-Cycle Cooling Water System program incorporates the

relevant inspection elements from programs that already are established at LGS, including the GL 89-13 program and ISI program.

The GL 89-13 inspection locations include nine locations that are inspected by UT. The inspection locations were selected to be representative of the large bore piping susceptibility to degradation. The current reinspection frequencies for these locations range from 1.5 years to 8 years based on estimated material loss rates determined through trending.

Additional UT inspections are performed at locations in the safety-related piping that have been determined to be susceptible to degradation as the result of visual observations during maintenance activities and walkdowns, operating experience, Guided Wave inspections, and augmented inspections from the application of ASME Code Case N-513. Augmented inspections that result from the application of ASME Code Case N-513 are selected based on physical similarity and susceptibility to corrosion as compared to the original inspection location.

UT inspection results that do not identify wall thickness less than 87.5% of the nominal pipe wall thickness do not require engineering review. The piping manufacturing tolerance for the LGS piping is 12.5% of nominal wall thickness. UT results in this range do not indicate that material loss is occurring. When UT inspections identify wall thickness that is less than 87.5% of nominal pipe wall thickness wall loss has occurred and the UT inspection results are evaluated by LGS engineering. For each inspection location, the minimum wall thickness to meet ASME design code structural integrity requirements is determined. Specific evaluations include hoop wall thickness, axial wall thickness, vacuum wall thickness, and buckling wall thickness. A determination of material loss rate is performed. Using this information, a reinspection frequency is determined to assure that subsequent inspections will occur prior to exceeding the pipe location minimum wall thickness requirements.

During the past five years, over 250 UT inspections have been performed, including repeat inspections at locations that did not satisfy the inspection acceptance criteria on the original inspection. Inspection results for these locations are tracked and trended to establish a material loss rate and reinspection frequency. Currently, LGS has 46 locations, including the 9 for GL 89-13, which are being inspected on frequencies that range from 6 months to 15 years.

LGS has also implemented pipe inspections utilizing long range guided wave (GW) technology since 2005 as a proactive measure to gain a better understanding of system condition. This technology is a low frequency ultrasonic guided wave technique developed for the rapid survey of pipes to detect both internal and external corrosion. While not accepted to satisfy the inspection requirements of the ASME Code, it provides a means to efficiently collect information on long runs of piping to assess general condition. The guided wave results identify locations for a more detailed inspection using standard UT techniques.

b. Material improvements of the ESW and RHRSW systems have been underway since 1996 and are being implemented in a phased approach. These improvements include:

1. Since 1996 a systematic replacement of carbon steel small bore vent and drain connections with stainless steel piping has been underway and continues in conjunction with maintenance activities on the systems. Over 160 valves have been replaced. This includes the replacement of small carbon steel globe valves with stainless steel ball valves to facilitate flushing and draining and to minimize accumulation of silt in the valve bodies.

2. In 2001 and 2002 approximately 70 feet of carbon steel piping was replaced with stainless steel for the ESW supply to the Emergency Diesel Generator heat exchangers.

3. In 2002, approximately 26 feet of the carbon steel Unit 1 HPCI room cooler return piping was replaced with stainless steel material.

4. Between 2005 and 2010, the Unit 1 and Unit 2 RHR pump compartment unit cooler and RHR pump motor oil cooler supply and return piping (4 inch NPS and under) was replaced with stainless steel material. This resulted in the replacement of approximately 1700 feet of carbon steel pipe with stainless steel material.

5. The unit cooler supply and return piping for the Unit 2C and 2D core spray pump compartments was replaced in 2011 resulting in the replacement of approximately 340 feet of carbon steel pipe with stainless steel.

Additional pipe enhancements are planned to reduce the susceptibility to material loss due to corrosion. These include:

1. The piping associated with the Unit 1 A, B, C, and D and the Unit 2 A and B Core Spray pump compartment unit coolers is planned to be replaced with stainless steel material by the end of 2014. This is expected to result in the replacement of 1000 feet of carbon steel piping.

2. Replacing degraded RHRSW piping located in the pipe tunnel. These replacements will take place over several refueling outages, beginning in 2012 and are currently scheduled to be completed in 2015.

Additional pipe replacements and improvements in material condition will be determined based on operating experience and piping inspection results.

The Open-Cycle Cooling Water System program is enhanced to include the replacement of the ESW piping associated with the Core Spray unit coolers and the degraded RHRSW piping in the pipe tunnel prior to entering the period of extended operation. Consistent with this response, the UFSAR Supplement for the Open-Cycle Cooling Water System program, A.2.1.12, and Open-Cycle Cooling Water System program description, B.2.1.12, are revised as shown in Enclosure B. The LRA Table A.5 commitment is also revised as shown in Enclosure C.

The combination of pipe inspections within the scope of existing LGS programs, pipe replacements, and material improvements to minimize the susceptibility to corrosion provides an effective means to manage aging of the safety-related service water systems. The objective of these activities is to maintain the safety-related service water systems capable of performing their intended functions while meeting design basis

requirements. The design basis includes compliance with ASME Section XI inspection and repair/replacement requirements and includes provisions for the short term acceptability of flaws within the constraints of ASME Section XI Code Case N-513, which has been approved for use by the NRC. Inspections and pipe improvements as described above will minimize the potential for degradation.

2. The buried safety-related service water piping for the ESW and RHRSW systems, as described in LRA Section B.2.1.29 was installed utilizing preventive and mitigative techniques such as external coatings for external corrosion control, the application of cathodic protection, and the use of quality backfill. Based on these design features, external corrosion is not expected.

   The internal surface of the buried piping is subject to process conditions (i. e. flowrate, water chemistry, temperature, time in service, biocide and chemical treatment) similar to the RHRSW piping in the pipe tunnel. Replacement of the degraded RHRSW piping in the pipe tunnel is planned between 2012 and 2015. Therefore, inspection results from the piping in the pipe tunnel will be applied to the buried piping. The piping is planned to be extensively examined through a variety of techniques because the piping will be removed from the tunnel and inspected without impacting plant operations or personnel radiation exposure. The inspections planned for removed piping include guided wave inspection of all piping removed, 100% visual inspection of all piping removed, UT examinations at locations determined by the visual and guided wave inspections, and destructive examination, including material analysis of corrosion products.

   During the pipe replacement in the tunnel, the buried piping is drained and is accessible for inspection. This opportunistic inspection of the buried piping coupled with the detailed inspection of the similar piping removed from the pipe tunnel will provide the information needed to address potential pipe degradation, if any, in the buried piping.

   The buried piping is also subject to internal process conditions similar to those that exist in the Safety-Related Service Water underground piping located in vaults. As described in LRA Section B.2.1.29, the Buried and Underground Piping and Tanks program is enhanced to inspect underground piping during each 10-year period beginning 10 years prior to the entry into the period of extended operation. The inspection results for the underground piping internal surfaces will be utilized in the assessment of potential degradation, if any, of the buried piping.

   Given that the buried piping is encased in fillcrete, providing structural support along the length of pipe and the buried pipe wall is thicker (0.500 inch) than the piping in the pipe tunnel (0.375 inch) additional margin exists when compared to the system aboveground piping. Therefore, opportunistic inspections of the buried piping as described in the LRA Section B.2.1.12 are appropriate since plans to address potential degradation, if any, of the buried piping will primarily be based on the inspection results from the RHRSW piping during the pipe replacements currently scheduled to be performed between 2012 and 2015. Clarification of Enhancement 1, described in LRA Section B.2.1.12, associated with the Open-Cycle Cooling Water system program is not required.

3. During the past five years, over 250 UT inspections have been performed, including repeat inspections at locations that did not satisfy the inspection acceptance criteria on the original inspection. These inspections have identified locations where the corroded

areas are considered independent as well as locations where multiple corrosion sites have been evaluated for cumulative impact as described below.

The evaluation of structural integrity for inspections performed under the Open-Cycle Cooling Water System program includes both nonsafety-related and safety-related piping systems. These engineering evaluations are performed to demonstrate compliance with piping design requirements, including structural integrity. Specific evaluations include hoop wall thickness, axial wall thickness, vacuum wall thickness, and buckling wall thickness.

For nonsafety-related piping, the evaluations are consistent with ASME Code Case N-597 and EPRI NP-5911 SP. For safety-related piping, the evaluation requirements of ASME Code Case N-513 are utilized to assess the structural integrity of degraded piping.

Piping inspections consist of a full circumferential ultrasonic thickness scan in the area at minimum of three inches on either side of the location of interest. Any areas found below 87.5% of nominal wall thickness are submitted to engineering for evaluation. The piping manufacturing under tolerance for the LGS piping is 12.5% of nominal wall thickness. The entire boundary of any area found thinned is recorded, even if it extends beyond the original specified examination area. When inspections identify multiple corrosion sites, they are evaluated utilizing the criteria of ASME Section XI, Article IWA-3000 to determine if they may be evaluated as separate flaws. Past inspections have identified locations where the corroded areas are considered independent as well as locations where multiple corrosion sites have been evaluated for cumulative impact. When multiple thinned areas are determined to not be independent, refined UT inspections may be performed to assure that the thinned areas are properly characterized. This information is used to perform the ASME code required structural integrity analyses. In most cases, a bounding flaw analysis is performed by using a larger than measured thinned area and less than measured reinforcement thickness at the perimeter of the assumed thinned area to encompass the areas of the multiple thinned areas.

Inspection results that do not meet established acceptance criteria are entered into the Corrective Action Program for review and evaluation, which includes extent of condition and impact on other SSC. For systems that are included in the Technical Specifications (ESW and RHRSW) or support Technical Specification systems, an operability evaluation is performed for degraded conditions that involve system leakage. The operability evaluation includes review for loss of flow, spraying water on surrounding SSC, flooding, and potential for flaw propagation. Based on the operability evaluation, any appropriate compensatory actions are identified and implemented until such time as repair or replacement is completed.

RAI B.2.1.12-2

Background:

The GALL Report AMP XI.M20, “Open-Cycle Cooling Water System,” relies on the implementation of recommendations in GL 89-13, which states that components exposed to raw water be inspected for corrosion, erosion, and biofouling.

Enhancement 2 of LRA Section B.2.1.12 states that periodic inspections for loss of material in the nonsafety-related service water system will be performed at a frequency in accordance with GL 89-13.

The staff noted that GL 89-13 does not specify inspection frequencies for loss of material, and the applicant's responses to that Generic Letter did not provide specific inspection frequencies for loss of material.

Issue:

It is unclear to the staff how the nonsafety-related service water system will be inspected to ensure that loss of material will be detected prior to loss of intended function.

Request:

Describe the number, frequency, and location of inspections for the nonsafety-related service water system, and, as appropriate, clarify the periodic inspection frequency in the associated enhancement.

Exelon Response

The Nonsafety-Related Service Water System will be inspected to ensure that loss of material will be detected prior to loss of intended function in a manner similar to the safety-related service water system. Unlike the Safety-Related Service Water System which is a common system serving both LGS units, a separate Nonsafety-Related Service Water System is provided for each LGS unit. Each unit's Nonsafety-Related Service Water System will be inspected at a minimum of five locations once every refueling cycle. The locations to be inspected are selected from those portions of the system that are in scope for License Renewal as shown on License Renewal system boundary drawings. Specific locations are determined based on susceptibility to aging effects.

Clarification of these Nonsafety-Related Service Water System inspections is provided in LRA Sections A.2.1.12, B.2.1.12, and Appendix A.5. Revised pages are included in Enclosures B and C.

RAI B.2.1.13-1

Background

GALL Report AMP XI.M21A, "Closed Treated Water Systems," recommends that piping, piping components, and piping elements exposed to treated water be managed for cracking due to SCC. GALL Report Section IX.D states that closed cycle cooling water >60°C (>140°F) makes SCC of stainless steel possible.

LRA Section B.2.1.13, "Closed Treated Water Systems," does not include cracking as an aging effect requiring management. LRA Tables 3.0-1 and 3.0-2 associate the closed cycle cooling water environment with the GALL Report environments of closed cycle cooling water and closed cycle cooling water >140°F.

Issue

It is not clear to the staff why SCC is not considered an aging effect requiring management in piping, piping components, and piping elements exposed to closed cycle cooling water.

In its review of AMR items with an environment of closed cycle cooling water, the staff cannot determine whether the temperature of the environment is above or below the GALL Report stress corrosion cracking threshold of 60°C (140°F).

Request:

1. Provide technical justification for not including SCC as an aging effect requiring management in the closed treated water systems.

2. For the AMR items with a closed-cycle cooling water environment, clarify whether the temperature of the environment is above or below the GALL Report stress corrosion cracking threshold of 60°C (140°F).

Exelon Response

1. GALL Report AMP XI.M21A for the Closed Treated Water Systems aging management program provides for the management of the loss of material, reduction of heat transfer, and cracking aging effects in closed treated water systems. However, the LGS Closed Treated Water Systems program does not manage cracking due to stress corrosion cracking because it is not applicable for LGS components. The temperature of the closed cycle cooling water environment is below the GALL Report stress corrosion cracking threshold of 60°C (140°F) for stainless steel.

2. The LGS license renewal systems that include a closed cycle cooling water environment managed by the Closed Treated Water Systems program are the:
   - Closed Cooling Water System described in LRA Section 2.3.3.2
   - Control Enclosure Ventilation System described in LRA Section 2.3.3.4
   - Emergency Diesel Generator System described in LRA Section 2.3.3.8
   - Primary Containment Ventilation System described in LRA Section 2.3.3.16
   - Reactor Coolant Pressure Boundary System described in LRA Section 2.3.1.1

   None of these systems include stainless steel components exposed to the environment of closed cycle cooling water >60°C (>140°F). Therefore, the aging effect of cracking due to stress corrosion cracking does not apply and the environment of closed cycle cooling water >60°C (>140°F) has not been included in LRA aging management evaluation Tables 3.3.2-2, 3.3.2-4, 3.3.2-8, 3.3.2-16, and 3.1.2-1.

As part of the extent of condition review performed for RAI 3.0.2-1, it was identified that LRA Table 3.0-1 for internal environments associated the closed cycle cooling water environment with the GALL Report environment of both closed cycle cooling water and closed cycle cooling water >60°C (>140°F). However, the closed cycle cooling water >60°C (>140°F) environment was not used. This environment has been deleted from LRA Table 3.0-1 in response to RAI 3.0.2-1.

RAI B.2.1.13-2

Background

The SRP-LR, Section 2.1.2.2, "Screening," states that the methodology used by an applicant should be consistent with the process described in Section 4.1, "Identification of Structures and Components Subject to an Aging Management Review and Intended Functions," of NEI 95-10, as referenced by Regulatory Guide 1.188. NEI 95-10, Section 4, "Integrated Plant Assessment," states that aging management reviews first identify the aging effects that require management, and then identify the AMPs to manage these aging effects.

LRA Table 3.3.2-2, "Closed Cooling Water System," identifies loss of material in carbon steel, copper, and stainless steel piping components exposed to closed cycle cooling water and references Table 1 items 3.3.1-45, 3.3.1-46, and 3.3.1-49 for these AMR results. LRA Table 3.3.2-2 states that the loss of material aging effect for these components is being managed by the Closed Treated Water Systems program. The aging effects/mechanisms ascribed to items 3.3.1-45, 3.3.1-46, and 3.3.1-49 are loss of material only due to general, pitting, galvanic or crevice corrosion. LRA Section 2.3.3.2 states that the closed cooling water system includes the reactor enclosure cooling water system.

LRA Section B.2.1.22, "One-Time Inspection," discusses a 2007 issue where ultrasonic test examinations confirmed erosion due to cavitation in reactor enclosure cooling water system supply piping to the RWCU non-regenerative heat exchanger and states that periodic inspections have been implemented to monitor the progression of this loss of material.

Issue

Although loss of material is identified as an aging effect in closed cooling water system piping, the corresponding AMR items are not associated with the aging mechanism of erosion due to cavitation noted in the operating experience discussion of the One-Time Inspection program. While the GALL Report includes a definition of cavitation in Table IX.F, "Aging Mechanisms," there are no AMR line items associated with cavitation for carbon steel, copper, or stainless steel components. As such, the AMP being credited for managing the resulting loss of material (Closed Treated Water Systems) does not appear to be appropriate. The applicant has a monitoring program in place to manage loss of material due to cavitation erosion that was not described in the LRA.

Request

1. Provide a detailed description of the proposed AMP to manage loss of material due to cavitation erosion in reactor enclosure cooling water system piping. Include a discussion of enhancements to the appropriate program elements of an existing AMP or a discussion of all ten program elements for a plant-specific AMP.

2. State the apparent or root cause of this degradation mechanism. Provide a summary and the conclusion of the extent of condition and extent of cause of this degradation mechanism, in order to establish that it is not applicable to other components within the scope of license renewal.

3. Explain why this aging effect/mechanism was not identified in the LRA and, as applicable, provide a summary and the conclusion of the extent of condition and extent of cause for this apparent discrepancy.

Exelon Response

1. The loss of material due to cavitation erosion in the reactor enclosure cooling water system piping will be managed by the Closed Treated Water Systems program. The program is described in LRA Appendix B.2.1.13 and includes an enhancement for periodic condition monitoring using NDE at an interval not to exceed once in 10 years during the period of extended operation.

   A Corrective Action Program Issue Report was created to address corrective actions for the cavitation erosion in the reactor enclosure cooling water piping to the 2A Reactor Water Cleanup System (RWCU) non-regenerative heat exchanger. An engineering evaluation was performed on the degraded piping and it was determined that continued service was acceptable. A recurring task has been put in place to monitor this piping periodically for cavitation erosion. The initial inspection frequency has been established at four years in order to develop a trend for the cavitation erosion. Once a trend has been established, the inspection frequency will be re-evaluated and adjusted accordingly. In no case will the inspection interval exceed once in 10 years during the period of extended operation. This recurring task will be annotated as an implementing activity for license renewal for the Closed Treated Water Systems program to ensure that these corrective actions are continued into the period of extended operation.

   LRA Table 3.3.2-2 for the Closed Cooling Water System is revised to include the aging effect of loss of material due to cavitation erosion in the reactor enclosure cooling water piping to the 2A Reactor Water Cleanup System (RWCU) non-regenerative heat exchanger, as shown in Enclosure B.

2. The cause of the loss of material in the reactor enclosure cooling water piping to the 2A Reactor Water Cleanup System (RWCU) non-regenerative heat exchanger is a design and operating deficiency that has resulted in cavitation erosion. Cavitation occurs when there is a flowing liquid stream that experiences a pressure drop below the fluid vapor pressure followed by a pressure recovery. Cavitation typically results in noise and vibration. The degradation is at an elbow located immediately downstream of a normally throttled valve and was initially identified by observation of noise and vibration. The engineering evaluation concluded that it is likely that the cavitation erosion began when the system was first placed in service as a result of the piping configuration and operating conditions.

   A review of operating experience for the past 10 years did not identify evidence of the loss of material due to cavitation erosion in any other portions of the reactor enclosure cooling water system for either LGS Unit 1 or Unit 2. Additionally, with the exception of the two events discussed in item 3 below, this review did not identify other instances of cavitation erosion for any in-scope component.

3. The loss of material due to cavitation erosion was not considered an applicable aging effect for the period of extended operation; therefore it was not included in the LRA. Cavitation erosion is the result of a design or operating deficiency that is addressed during the current term of operation by the LGS Corrective Action Program which ensures that corrective actions are taken prior to the loss of intended function.

A review of operating experience for the past 10 years identified two reported occurrences of the loss of material due to cavitation erosion in in-scope components. These involved cavitation erosion in valve bodies. These conditions as described below were not considered age related and were resolved within the LGS Corrective Action Program.

- RHR shutdown cooling injection outboard primary containment isolation valve HV-051-1F015A (boundary drawing LR-M-51, sht 1, coordinate E-3) was identified in 1998 as having cavitation erosion on two of the three in-body disc guides and on the interior lip of the valve body where the seat ring is threaded into the body. The areas of erosion did not encroach on the pressure boundary. The cavitation erosion was attributed to improper throttling of the valve.

  This valve has had a history of in-body cavitation erosion and periodic internal inspections were put in place to monitor the rate of degradation. Subsequent to discovery, the operation of this valve was altered to eliminate the cavitation by no longer using this valve in a throttle function. As a result, the condition that promoted cavitation erosion was eliminated and the in-body degradation has not progressed between the period of 1998 to 2010. The periodic internal inspections were determined to no longer be required to monitor the cavitation erosion.

- Moisture separator drain level control valve LV-C-001-103A (boundary drawing LR-M-01, sht 2, coordinate B-5) was identified in 2010 as having cavitation erosion on the in-body bottom of the valve body. This valve is normally closed. The erosion was the result of seat leakage and resultant flashing. As part of the corrective action, the valve internals were replaced to eliminate the seat leakage. This portion of the system is included within the scope of the Flow Accelerated Corrosion Program as described in LRA Appendix B.2.1.10.

RAI B.2.1.15-1

Background

The GALL Report AMP XI.M24, “Compressed Air Monitoring,” “monitoring and trending” program element recommends that daily readings of system dew point are recorded and trended. The “monitoring and trending” program element in the applicant’s LRA AMP basis document for the Compressed Air Monitoring program states that the instrument air system dew point is continuously monitored and alarmed, inspected weekly, and recorded quarterly. The basis document also states that the primary containment instrument gas system’s dryer desiccant outlet moisture indicator is verified weekly.

The LRA AMP program basis document also states that trending is accomplished by satisfactory completion of the surveillances and quarterly recorded values and Issue Reports are initiated for alarms or test or inspection results that do not satisfy the established criteria.

Issue

It is not clear to the staff that the LRA is consistent with the GALL Report because, for the instrument air system, the dew point is not recorded on a daily basis, and for the primary

containment instrument gas system, dew point is not recorded. It is also not clear to the staff that the applicant is comparing prior data points to current data points during trending.

Request

1. Explain why weekly inspections and quarterly recording of the instrument air system dew point are sufficient to detect potentially unacceptable levels of moisture within in-scope components, or propose an alternative to how often the system's dew point will be recorded and trended.

2. For the primary containment instrument gas system's dryer desiccant outlet moisture indicator, explain why using a desiccant outlet moisture indicator in lieu of monitoring dew point, and why verifying the desiccant outlet moisture indicator on a weekly basis are sufficient to detect potentially unacceptable levels of moisture within in-scope components, or propose an alternative to the recorded parameter and how often it will be recorded and trended.

3. State whether prior data points are compared to current data points during trending, and if they are not, state why the trending of data points will be sufficient to detect changes in air quality prior to degraded air quality impacting the ability of the instrument air systems to meet their current licensing basis function(s).

Exelon Response

1. GALL Report AMP XI.M24 utilizes the aging management aspects of the commitments for Generic Letter 88-14, "Instrument Air Supply System Problems Affecting Safety-Related Equipment", that are applicable to license renewal, primarily the loss of material due to corrosion. Element 4 of this AMP recommends periodic samples and tests of air quality for moisture in accordance with industry standards, such as ANSI/ISA-S7.0.01-1996. This standard establishes a dew point criterion, and states that "A continuous monitoring alarm system is recommended; however, periodic checks should be scheduled to help ensure delivery of instrument quality air to end-use devices". GALL Report AMP XI.M24 Element 4 also states that "Typically, compressed systems have in-line dew point instrumentation that either checks continuously using an automatic alarm system or is checked at least daily to ensure that moisture content is within specifications". The purpose of monitoring moisture is to reduce the potential for loss of material due to corrosion.

   The Instrument Air system is monitored continuously and equipped with a Main Control Room alarm system to ensure moisture content is within specifications. This practice is consistent with the guidance in GALL Report AMP XI.M24 Element 4. Operators inspect and verify that the instrument air dryer outlet dewpoint is within its required range on a weekly basis to supplement the continuous monitoring activity. In addition, the LGS Generic Letter 88-14 commitments include verification of instrument air quality at safety-related components each refueling outage, which determines the level of moisture, hydrocarbon content, and particulate size. This test is performed at three randomly selected locations, including a Main Steam Isolation Valve operator manifold and a Control Rod Drive Hydraulic Control Unit air supply header. This verification of instrument air quality at safety-related components each refueling outage validates the continuous and weekly inspection activities. Therefore, the continuous monitoring and alarm system along with weekly operator inspections of the instrument air system dew point are sufficient to detect potentially unacceptable levels of moisture within in-scope components. System manager reviews of

system health parameters are also performed on a quarterly basis to monitor system performance and ensure early detection of equipment problems.

2. The Primary Containment Instrument Gas system utilizes the dessicant dryer outlet moisture indicator to monitor moisture. Operators inspect the moisture indicator on a weekly basis to verify that moisture content is in an acceptable range. The use of a moisture indicator in place of direct dewpoint monitoring is consistent with the ANSI/ISA-S7.0.01 standard, which states that "Various methods are available for determining moisture content. These methods include but are not limited to, dew point instruments, dewcup, chilled mirror, cloud chamber," etc.

   GALL Report AMP XI.M24 states that "this AMP does not change the applicant's docketed response to NRC GL 88-14 for the rest of its operations. The program utilizes the aging management aspects of the applicant's response to NRC GL 88-14 for license renewal with regard to preventative measures, inspections of components, and testing to ensure that the compressed air system will be able to perform its intended function for the period of extended operation." The LGS Generic Letter 88-14 commitments include verification of instrument gas quality at safety-related components each refueling outage, which determines the level of moisture, hydrocarbon content, and particulate size. This test is performed at three randomly selected locations, including a Main Steam Isolation Valve operator manifold and an Automatic Depressurization System Main Steam Relief Valve operator. This verification of instrument gas quality at safety-related components each refueling outage verifies that the dessicant dryer outlet moisture indicator is a valid representation of the gas quality. Therefore, use of the desiccant dryer outlet moisture indicator to verify acceptable dryer outlet moisture on a weekly basis, in conjunction with the GL 88-14 instrument gas quality verification, is sufficient to detect potentially unacceptable levels of moisture within in-scope primary containment instrument gas system components.

3. GALL Report AMP XI.M24, Element 5, recommends air quality analysis and trending using the guidance of ASME O/M-S/G-1998, Part 17. The Compressed Air Monitoring program is enhanced to meet this guidance, to perform periodic analysis and trending of air quality monitoring results. This enhancement ensures that trending of data points are sufficient to detect changes in air quality prior to degraded air quality impacting the ability of the instrument air systems to meet their current licensing basis function(s). The UFSAR Supplement LRA Section A.2.1.15 and LRA Section B.2.1.15 are revised as shown in Enclosure B to add an enhancement to the Compressed Air Monitoring program to perform trending. In addition, LRA Table A.5, commitment 15 is revised as shown in Enclosure C.

RAI B.2.1.15-2

Background

SRP-LR Table 3.0-1 states that the UFSAR Supplement for the "Compressed Air Monitoring" program should reference the applicant's crediting of its response to GL 88-14 and standards such as ISA-S7.0.1-1996 as guidance for testing and monitoring air quality and moisture. LRA Section A.2.1.15, Compressed Air Monitoring program, does not reference the above.

Issue

The licensing basis for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR Supplement.

Request

Provide further information showing why referencing the response to GL 88-14 and standards such as ISA-S7.0.1-1996 as guidance for testing and monitoring air quality and moisture is not required for the UFSAR Supplement, or revise LRA Section A.2.1.15 to include key aspects of the program that provide guidance for testing and monitoring air quality and moisture.

Exelon Response

The UFSAR Supplement in LRA Section A.2.1.15 is revised to reference the GL 88-14 response per the guidance in the Standard Review Plan, NUREG-1800, Table 3.0-1, for Compressed Air Monitoring as shown in Enclosure B.

RAI B.2.1.17-1

Background

The “scope of program” program element of GALL Report AMP XI.M26, “Fire Protection,” states that the program includes visual inspections of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire resistant materials that perform a fire barrier function.

The LGS UFSAR states that gypsum fire barrier walls, fiberglass sleeving fire barriers, and refractory material raceway fire stops covered with silicone rubber are used as fire barriers. However, the LRA does not include any aging management results for components constructed of these materials.

Issue

It is not clear to the staff whether the gypsum, fiberglass sleeving, and refractory material fire barriers discussed in the UFSAR are being managed for aging.

Request

Clarify if the gypsum, fiberglass sleeving and refractory material fire barriers discussed in the UFSAR are within the scope of license renewal. If they are, explain how the gypsum, fiberglass sleeving, and refractory material fire barriers discussed in the UFSAR are being managed for aging.

Exelon Response

UFSAR section 9.5.1.2.12 identifies that the south and east walls of the Remote Shutdown Room, Auxiliary Equipment Room, and the Control Room peripheral room ceilings are a gypsum drywall assembly. UFSAR Appendix 9A in response to BTP Guideline Item 43 identifies that one type of fire rated penetration seal uses ceramic fiber in the space between the penetrating object and the edge of the penetration. Raceways in the Power Generation Control

Complex in the Auxiliary Equipment Room have fire stops that consist of refractory material covered by silicone rubber. Both the ceramic fiber and refractory material are alumina silica products and are included in the material type of "alumina silica" in revised LRA Table 3.3.2-9. These materials were inadvertently omitted from the LRA. Accessible barriers using these materials are inspected as a part of the existing periodic LGS Fire Barrier inspections.

UFSAR section 8.1.6.1.14 discusses the use of fiberglass sleeving. This material is wrapped around electrical cables as an additional barrier when physical space is not available to meet Regulatory Guide 1.75 separation requirements. The fiberglass sleeving is not a fire barrier in accordance with the LGS Fire Protection Evaluation Report described in UFSAR Appendix 9A and does not perform a License Renewal intended function for fire protection in accordance with 10 CFR 54.4(a)(3).

LRA Section 3.3.2.1.9, Table 3.3.2-9, and Table 3.3-1 have been revised to include the alumina silica and gypsum materials, their aging effects and aging management programs as shown in Enclosure B.

RAI B.2.1.17-2

Background

The “detection of aging effects” program element of GALL Report AMP XI.M26, “Fire Protection,” recommends that visual inspections be performed by fire protection qualified personnel of not less than 10 percent of each type of penetration seal during walkdowns, and that the scope of the inspections be expanded if any sign of seal degradation is detected.

LRA Section B.2.1.17, Fire Protection, states that not less than 10 percent of each type of penetration seal is inspected at least once per refueling cycle, except for internal conduit seals which are not accessible for visual inspection.

Issue

The LRA does not discuss how internal conduit seals, which are not accessible for visual inspection, are managed for aging.

Request

Explain how internal conduit seals which are not accessible for visual inspection are managed for aging.

Exelon Response

GALL Report AMP XI.M26, "Fire Protection", element 4, states that visual inspection is performed in accordance with an NRC-approved fire protection program (e. g. Technical Requirements Manual). The LGS NRC-approved fire protection program described in the LGS Technical Requirements Manual Section 4.7.7.1 specifically excludes internal conduit seals from visual inspection.

Conduits that penetrate fire barriers are sealed internally to prevent the passage of smoke and hot gasses. These internal conduit seals are not accessible for visual inspection. The aging effects that are typically associated with the silicone foam elastomer that is used for the conduit internal seals are hardening and loss of strength, loss of material due to wear and loss of sealing. The conduit seals are not exposed to high temperatures or wear due to relative motion between associated surfaces. Therefore, hardening and loss of strength and loss of material are not applicable aging effects.

Regarding loss of sealing, conduits which extend less than five feet on either side of the fire barrier are sealed with at least nine inches of silicone foam. For those conduits which extend five feet or more on both sides of the fire barrier, the conduits are sealed with at least two inches of silicone foam on both sides of the barrier. These features of the plant are described in the LGS UFSAR Section 9A, Fire Protection Evaluation Report. Even if degradation were to develop in the foam material, given the length of the seal it is unlikely that the degradation would extend the entire length of the seal and provide a leak pathway. The electrical cables routed in the conduits are manufactured using cable insulation and jacketing systems that pass the IEEE flame test except for some cable associated with the lighting, communication, and grounding systems, and (for Unit 2 only) some of the wires which are used to scan the location of embedded PVC conduits. Therefore, flame propagation through the seal will not occur.

The design of the conduit internal seals and conduit configuration described above provides reasonable assurance that a loss of sealing function will not occur and, therefore, aging management of the conduit internal seals is not warranted.

RAI B.2.1.17-3

Background

The “detection of aging effects” program element of GALL Report AMP XI.M26, “Fire Protection,” states that visual inspections are performed by fire protection qualified personnel of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials.

LRA Section B.2.1.17, Fire Protection, states that the personnel performing inspections are qualified and trained to perform the inspection activities. However, during the audit, the staff noted that the personnel responsible for performing fire barrier inspections are maintenance-qualified personnel; not fire protection-qualified personnel.

Issue

It is not clear to the staff whether the personnel performing fire barrier inspections will be adequately trained and qualified to identify fire barrier deficiencies.

Request

Describe the training and qualifications of the personnel responsible for performing fire barrier inspections.

Exelon Response

Fire protection barrier inspection parameters and acceptance criteria are identified in plant procedures and are consistent with Fire Protection program requirements. Visual examinations are performed by experienced site personnel in accordance with these procedures. Typically, the inspections are performed by personnel who are also qualified by training and demonstration to install and repair fire barriers and understand the purpose of the barriers, have knowledge of barrier types and materials of construction, and inspect newly installed and repaired barriers. Any inspections that do not meet established procedure acceptance criteria are reviewed and evaluated by the Fire Protection Program Engineer who has the appropriate fire protection program qualifications.

RAI B.2.1.19-1

Background

The “preventive actions” program element of the LRA Section B.2.1.19, Aboveground Metallic Tanks, states that there is no caulking or sealant at the base of the backup fire water storage tank. The GALL Report AMP XI.M29, Aboveground Metallic Tanks, “preventive actions” program element, recommends installation of sealant or caulking at the tank to foundation interface to minimize the amount of water and moisture penetrating the interface, which could lead to corrosion of the tank bottom.

Issue

During the audit, the staff reviewed the applicant’s program basis document for the Aboveground Metallic Tanks program which stated that the backup fire water storage tank was installed on a compacted oil treated sand bed. The document also stated that no caulking or sealant was installed at the tank to soil interface. The staff lacks sufficient information (e.g., thickness of the sand bed, tank bottom coating) to determine if the backup fire water storage tank will be capable of performing its current licensing basis function(s) based on the applicant’s currently proposed tank bottom inspection frequency and the potential for water intrusion at the tank’s base.

Request

State the basis for concluding that there is a reasonable assurance that the backup fire water storage will be capable of performing its current licensing basis function(s) in the absence of sealant or caulking at the tank’s base.

Exelon Response

The design of the Backup Water Storage Tank does not include caulking or sealant at the base of the tank. The tank is installed directly on a compacted oil treated sand bed, and as such, there is no joint between the tank bottom and sand bed that is suitable for utilization of sealant or caulking. The thickness of the compacted sand bed is unknown. A small valve pit does extend under the tank base to accommodate the tank supply and discharge pipes, however, there is no caulking or sealant at the valve pit to tank bottom interface. The tank bottom external surface is coated with a bitumastic/ asphalt coating.

The tank bottom condition and any degradation attributed to water intrusion in the sand bed may be determined by performing two inspections and trending results. Therefore, the enhancement to inspect the tank bottom is revised to perform one tank bottom inspection within five years prior to entering the period of extended operation and recurring inspections on a five year frequency. UT plate thickness measurements will be obtained around the circumference of the tank base, on each plate in the tank base, and at any locations where the interior coating has deteriorated and needs repair. If no bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed whenever the tank is drained for maintenance, consistent with GALL Report AMP XI.M29.

The tank bottom coating system in combination with the enhanced inspections will provide reasonable assurance that degradation is detected and repaired prior to loss of intended function of the Backup Water Storage Tank.

Consistent with this response, the UFSAR Supplement for Aboveground Metallic Tanks, A.2.1.19, and Aboveground Metallic Tanks program description, B.2.1.19, are revised as shown in Enclosure B. The LRA Table A.5 commitment is also revised as shown in Enclosure C.

RAI B.2.1.19-2

Background

The “detection of aging effects” program element, Enhancement 2, of the LRA Section B.2.1.19, Aboveground Metallic Tanks, states that in order to provide for visual inspection of the external surface of the backup fire water storage tank on a two-year frequency, insulation will be removed on a sampling basis. The GALL Report AMP XI.M29, “Aboveground Metallic Tanks,” recommends that the external surface of the tank be visually inspected at each outage to confirm that the paint is intact.

Issue

During the AMP audit, the applicant stated that they could not determine the manufacturer of the sprayed on thermal insulation on the exterior of the backup fire water storage tank. As a result, they could not conclude that the exterior membrane and insulating material is water resistant. In addition, during the audit the staff walked down the tank and noted that there are several locations where the outer insulation jacketing is damaged, thus exposing the interior foam style insulation, and possibly the tank’s external surface, to water intrusion. Given that the applicant did not state the amount of insulation that will be removed during the two-year frequency inspections and the potential for water to be trapped between the external surface of the tank and the insulation, the staff lacks sufficient information to conclude that the tank will meet its current licensing basis function(s) throughout the period of extended operation.

Request

State how much insulation will be removed from the backup fire water storage tank during its two-year frequency external surface inspections. In addition, state the basis for why the amount

of insulation to be removed is sufficient to detect potential tank exterior degradation prior to its impacting the ability of the tank to perform its current licensing basis function(s).

Exelon Response

The Backup Water Storage Tank has a diameter of 46 ft-6 inches and a side wall height of 40 feet and is fabricated from carbon steel materials. The tank exterior surface is painted with an organic zinc-rich primer covered by enamel. The entire tank, including the domed roof, is covered with a spray-on polyurethane foam type insulation with a fiberglass fabric outer layer. Electrical heat tracing cables are installed between the tank surface and the polyurethane foam insulation.

The inspection of the tank outer surface prior to entering the period of extended operation will include locations where the insulation will be removed to demonstrate that the insulating materials are effective in preventing moisture intrusion to the tank painted surface. The visual inspection will include removal of the foam insulation at a minimum of 25 locations, each location exposing approximately one square foot of tank surface. The selected inspection locations will include areas where the polyurethane foam and insulation jacketing (fiberglass skin) are intact as well as areas where the foam or insulation jacketing shows visible signs of degradation. At least 10 of the 25 locations to be inspected will be located near the base of the tank wall around the perimeter where moisture intrusion is most likely to occur. If this visual inspection demonstrates that the insulating polyurethane foam and fiberglass skin is effective in preventing moisture from contacting the tank surface and water is not being trapped between the insulation and tank wall, then subsequent inspections may include a reduced number of inspection locations. Subsequent inspections, conducted on a two year frequency, will include those locations where the insulation is deteriorated or has evidence of water intrusion. If no insulation deterioration is identified, insulation will be removed on a sampling basis to permit inspection of the tank surface. In either case, a minimum of four locations will be inspected and each location will include an approximate one square foot of tank surface.

The inspection of the tank outer surface at a minimum of 25 locations provides reasonable assurance to demonstrate the effectiveness of the insulating material for preventing moisture intrusion to the tank painted surface.

Consistent with this response, the UFSAR Supplement for Aboveground Metallic Tanks, A.2.1.19, and Aboveground Metallic Tanks program description, B.2.1.19, are revised as shown in Enclosure B. The LRA Table A.5 commitment is also revised as shown in Enclosure C.

RAI B.2.1.20-1

Background

GALL AMP XI.M30, “Fuel Oil Chemistry,” states that, “Periodic multilevel sampling provides assurance that fuel oil contaminants are below unacceptable levels. If tank design features do not allow for multilevel sampling, a sampling methodology that includes a representative sample from the lowest point in the tank may be used.”

Issue

The LRA basis document states that the LGS Fuel Oil Chemistry program will be enhanced to periodically analyze for water and sediment and microbiological organisms in the Diesel Generator Diesel Oil Storage Tanks. The samples for analysis are taken by running the fuel oil transfer pumps, which take suction 11 inches from the bottom of the Diesel Generator Diesel Oil Storage Tanks, to transfer fuel oil to a sample collection point in the Diesel Generator Day Tank room, which may not provide a representative sample.

Request

Explain how the current LGS sample collection methodology assures that fuel oil contaminants are below unacceptable levels, as is recommended in GALL AMP XI.M30.

Exelon Response

GALL Report AMP XI.M30 Element 4, Detection of Aging Effects, states that periodic multilevel sampling provides assurance that fuel oil contaminants are below unacceptable levels. If tank design features do not allow for multilevel sampling, a sampling methodology that includes a representative sample from the lowest point in the tank may also be used. Program Element 3, Parameters Monitored/Inspected, identifies parameters monitored as water and sediment content, total particulate concentration, and the levels of microbiological organisms.

GALL Report AMP XI.M30, Revision 2, incorporated the option to allow a more conservative sampling method in lieu of multilevel sampling. This is addressed in resolution to comment 187 in Table II-21 of NUREG-1950, "Disposition of Public Comments and Technical Bases for Changes in the License Renewal Guidance Documents NUREG-1801 and NUREG-1800". The technical basis states that for tank designs that do not allow for multi-level sampling, the staff has determined that a representative sample taken from the bottom of the tank provides an acceptable alternative to multi-level sampling. It additionally states that different designs should be reviewed on a case-by-case basis to ensure they are either equivalent or more conservative to multi-level sampling. The sampling method used for the LGS EDG fuel oil storage tanks, although not a bottom sample, is a more conservative sample than a multilevel sample as demonstrated by the following:

In lieu of multilevel sampling, samples of the LGS Emergency Diesel Generator Oil Storage Tanks are obtained from the diesel generator fuel oil transfer pump discharge piping while the transfer pump is running. Prior to collecting the sample, the piping is flushed to ensure that the collected sample is representative of the tank contents.

The fuel oil transfer pump is a sump pump that takes suction 11 inches from the bottom of the Emergency Diesel Generator Oil Storage Tank. There are no design features on the tanks such as process piping or drains that would allow for sampling at a lower tank elevation. The tank includes a sump for the collection of condensate but no physical drain piping is provided for sampling the sump.

GALL Report AMP XI.M30, in the Program Description, refers to ASTM D 4057-95, "Manual Sampling of Petroleum and Petroleum Products" for sampling methods. This ASTM standard does not define "multilevel sample" but defines "all-levels sample", "composite sample", and "running sample" which would constitute a "multilevel sample".

The requirements from this ASTM standard for these sampling methods are as follows:

All-levels sample - The sample container is lowered to a point as near as possible to the draw-off level, opened, and then raised at a rate such that the sample container is 75 percent full as it emerges from the liquid. This method includes a lower sample location equivalent to the current LGS practice but it includes mixing of the oil sampled from the lower elevation with oil obtained from higher tank elevations as the sample container is raised up through the tank.

Composite sample - This method involves the blending of spot samples. The lowest spot sample used as determined by ASTM D 4057 Table 2 is 20 percent of the tank diameter above the tank bottom based on a tank capacity of 41,500 gallons and a minimum Technical Specification volume of 33,500 gallons. The EDG fuel oil tank is 144 inches in diameter, resulting in a lower sample location of 28 inches from the tank bottom. This is above the tank level currently used. This method also involves mixing of the oil sampled at the lower elevation since it is mixed with oil samples from middle and upper sampling levels.

Running Sample - The sample container is lowered to the level of the bottom of the tank outlet connection and returned to the top of the oil at a uniform rate such that the sample container is about 75 percent full when withdrawn from the oil. This method includes a lower sample location equivalent to the current LGS practice but it includes mixing of the oil sampled from the lower elevation with oil obtained from higher tank elevations as the sample container is raised up through the tank.

All these methods include tank sampling levels that are at an equivalent height or are at a higher height in the tank than the sampling methods used at LGS. These methods also include mixing of the lower level oil with oil obtained at higher levels in the tank. Therefore, the LGS sample method is more conservative than the "multilevel" sample methods described in ASTM D 4057-95.

GALL Report AMP XI.M30 Element 2, Preventive Actions, states that periodic cleaning of a tank allows removal of sediments, and periodic draining of water collected at the bottom of a tank minimizes the amount of water and the length of contact time. Accordingly, these measures are effective in mitigating corrosion inside diesel fuel oil tanks. The periodic testing for, and removal of, water from the tank sump in accordance with the plant Tech Specs, and, the periodic draining, cleaning, and internal inspection of the tanks in accordance with GALL Report AMP XI.M30 Element 2 provides further assurance that fuel oil contaminants are maintained below unacceptable levels and aging effects are managed during the period of extended operation.

RAI B.2.1.23-1

Background

The program basis document for the Selective Leaching program states the acceptance criteria are as follows: no visible signs of selective leaching, no more than a 20 percent reduction in hardness, or no reddish copper color (i.e., for copper alloy greater than 15 percent zinc). The GALL Report AMP XI.M33, “Selective Leaching,” recommends similar acceptance criteria.

Issue

The applicant proposes to use alternative mechanical examination techniques, for which none of the above acceptance criteria is applicable. It is not clear to the staff what acceptance criteria will be used when alternative mechanical examination techniques are implemented.

Request

State what acceptance criteria will be used when alternative mechanical examination techniques are implemented.

Exelon Response

The LGS Selective Leaching program follows the GALL Report AMP XI.M33 recommendations to perform one-time visual inspections, coupled with either hardness measurements or other mechanical examination techniques. The approach is to perform hardness measurements, and where hardness testing cannot be performed, other mechanical examination techniques such as chipping or scraping will be performed instead. The purpose of mechanical techniques is to reveal a visual indication of selective leaching. Industry operating experience indicates that when selective leaching occurs, it leaves behind a porous material consisting of graphite, voids and rust (graphitization) or a weakened and corroded structure (dezincification). Mechanical methods of chipping and scraping will expose such a corroded or weakened component structure, and a visual inspection will be effective in identifying this type of degradation.

The acceptance criterion of "no visible signs of selective leaching" is applicable to these mechanical examination techniques.

RAI B.2.1.25-1

Background

GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components,” recommends that stainless steel piping, piping components, and piping elements and tanks exposed to air-outdoor (external) need to be managed for cracking due SCC.

SRP-LR Section 3.3.3.2.3 states that the GALL Report recommends further evaluation to manage cracking due to SCC of stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air environments containing sufficient halides (primarily chlorides) and in which condensation (including rain) is possible. SPR-LR Section 3.3.3.2.3 further states that applicable outdoor air environments include those plants within a half a mile of a highway which is treated with salt in the wintertime and those having cooling towers where the water is treated with chlorine or chlorine compounds.

LRA Section 3.3.2.2.3 states that outdoor air is assumed to be an aggressive environment having a potential concentration of contaminants that could promote SCC. LRA Section 3.3.2.2.3 further states that SCC of stainless steels exposed to outdoor air is considered plausible only if the material temperature is above 140°F. The LRA states that stainless steel components in outdoor Auxiliary Systems are not susceptible to SSC since temperatures of these components do not exceed < 140ºF at LGS.

Issue

LRA Table 3.0-1 describes air – outdoor (external) as an environment that is periodically subject to wetting (condensation, rain, etc.) which the staff believes could introduce halides (i.e., road salt, etc.) which are known to contribute to SCC, regardless of temperature. LRA Section 2.4.7 further states that two circulating water chlorine and acid feed enclosures are used to maintain the chemical properties of the cooling tower basins which can also contribute to halides in condensation.

Request

Provide technical justification as to why the LRA AMP does not consider SCC to be an aging effect requiring management for the stainless steel components in the Auxiliary Systems that are subjected to wet external environments. The technical justification needs to address the consideration of halides in the external environment.

Exelon Response

The LRA AMP does not consider SCC to be an aging effect requiring management for the stainless steel components in the Auxiliary Systems that are subjected to wet external environments. The Limerick site is located more than 80 miles from the coast of the Atlantic Ocean. The nearby major transportation routes are more than one-half mile from the site and include: U.S. Highway (US-) 422, an east-west highway passing approximately 1.5 miles north of the site; Pennsylvania Route (PA-) 100, a north-south highway passing approximately 4 miles west of the site; and PA-724, a southeast-northwest highway passing approximately 1 mile southwest of the site. Although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant. Therefore, the environment is not expected to be aggressive. A review of LGS plant operating experience over a ten year period was performed, and no evidence of cracking in outdoor stainless steel components was identified. Recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition. Therefore, the outside air at LGS is not conducive to stress corrosion cracking.

The discussion of the outdoor air environment in LRA Section 3.3.2.2.3 does not correctly address the attributes for susceptibility to stress corrosion cracking in outdoor air. An extent of condition review revealed similar wording in LRA Sections 3.2.2.2.6 and 3.4.2.2.2. LRA Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2 are revised as shown in Enclosure B to correct the further evaluation discussion to state the reasons that the outdoor air environment is not conducive to stress corrosion cracking. Additionally, LRA AMR Tables 3.3.2-8, 3.3.2-22, 3.4.2-1, and 3.4.2-2 are revised as shown in Enclosure B to provide clarification that cracking is not applicable for LGS in an outdoor air environment.

RAI B.2.1.26-1

Background

GALL Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” “scope of program” element describes the aging effects that are addressed within the program such as loss of material.

The LRA credits LRA AMP B.2.1.26, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” for managing the following aging effects; loss of fracture toughness, reduction of heat transfer, and cracking (in Tables 3.3.2-21, 3.3.2-20, and 3.3.2-19, respectively). LRA AMP B.2.1.26’s program description section does not include these aging effects within that section.

Issue

LRA AMP B.2.1.26 does not include all of the aging effects addressed by the aging management program.

Request

Revise LRA AMP B.2.1.26 to include the program’s aging effects of loss of fracture toughness, reduction of heat transfer and cracking.

Also include the appropriate details such as parameters to be monitored, acceptance criteria and detection of aging effect elements necessary to support these additional program aging effects.

Exelon Response

LRA AMP B.2.1.26 and LRA UFSAR Supplement Section A.2.1.26 are revised as shown in Enclosure B to include the program's aging effects of loss of fracture toughness, reduction of heat transfer, and cracking. The basis for including each of these aging effects in this program, including details of the parameters to be monitored, acceptance criteria, and detection of aging effects elements, is as follows.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program was selected to manage the loss of fracture toughness aging effect for the B and C RWCU pump casings. These pump casings are constructed of cast austenitic stainless steel, and are exposed to a high temperature (>482°F) reactor coolant environment. Loss of fracture toughness is an applicable aging effect for this material/environment combination. The B and C RWCU pumps are ASME Class 3 components.

GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)", applies only to ASME Class 1 components, and is therefore not applicable to the RWCU pumps. However, the inspection requirements of this program to monitor and inspect for loss of fracture toughness were reviewed. GALL Report AMP XI.M12 states "The program does not directly monitor for loss of fracture toughness that is induced by thermal aging; instead, the impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components". For ASME Code Class 1 pumps and valves, GALL Report AMP XI.M12 endorses the ASME Section XI ISI program to manage aging. Under ASME Section XI Table IWB-2500-1, Class 1 pumps

are subject to a visual inspection of the internal surfaces when the pumps are disassembled for maintenance. However, the B and C RWCU pumps are Class 3 components, and the requirements of Table IWD-2500-1 apply. Table IWD-2500-1 does not require the internal surfaces of pumps to be inspected at all. Therefore, the loss of fracture toughness aging effect for the B and C RWCU pumps would not be effectively managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program.

As a result, managing the B and C RWCU pumps for loss of fracture toughness is by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program (LRA B.2.1.26), where they will receive a visual inspection for evidence of cracking. This is consistent with the inspection requirements for Class 1 pumps by the ASME Section XI program and GALL program XI.M12. Any evidence of cracking which is identified during visual inspection will be evaluated for potential loss of intended function under the Corrective Action Program.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program was selected to manage the reduction of heat transfer aging effect for the air side of various Reactor Enclosure and Control Enclosure ventilation system coolers and the Emergency Diesel Generator System combustion air coolers. While the cooling water side of these components is monitored under programs such as the Open-Cycle Cooling Water System (B.2.1-20) and Closed Treated Water Systems (B.2.1-21A) programs, these programs do not address the air side environment for all of these coolers. Accumulation of foreign material and debris on the air side of these coolers are indicators of reduction of heat transfer. Visual inspection performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is an appropriate method to identify accumulation of foreign material and debris in these coolers. Under this program, any evidence of material accumulation or fouling which is identified during visual inspection will be evaluated for potential loss of intended function under the Corrective Action Program.

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program was selected to manage the cracking aging effect for stainless steel components in the waste water >140°F environment. Cracking is an applicable aging effect for this material/environment combination, and is not addressed by other GALL programs. Since these components are in a more aggressive environment than the environments addressed by GALL Report AMP XI.M32, a one-time inspection is not appropriate. Therefore, these stainless steel components exposed to a waste water >140°F environment are included in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to monitor these components for cracking. Visual inspection techniques will follow the guidelines described in GALL Report AMP XI.M32, "One-Time Inspection", to detect cracking. Any evidence of cracking which is identified during visual inspections of the stainless steel components in the waste water >140°F environment will be evaluated for potential loss of intended function under the Corrective Action Program.

RAI B.2.1.26-2

Background

GALL Report AMP XI.M38 states that the program is intended for "...internal surfaces of metallic piping, piping components, ducting, polymeric components, and other components that are exposed to air-indoor uncontrolled, air outdoor, condensation, and any water system other than

open-cycle cooling water system (XI.M20), closed treated water system (XI.M21A), and fire water system (XI.M27)."

LRA AMP B.2.1.26, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," states that "This program will manage the aging effects of loss of material for metallic and elastomeric components, and hardening and loss of strength for elastomers, in air/gas wetted, closed cycle cooling water, diesel exhaust, fuel oil, lube oil, raw water, treated water, and waste water environments."

Issue

The staff considers the application of LRA AMP B.2.1.26 to components in environments of fuel oil, lube oil, and closed cycle cooling (i.e., closed treated water), to be beyond the scope of GALL Report AMP XI.M38 and therefore requires an appropriate technical justification, consistent with the SRP-LR.

Request

Provide a technical justification for including components in environments of fuel oil, lube oil, and closed cycle cooling (i.e., closed treated water) within the scope of LRA AMP B.2.1.26, including how applying this AMP will ensure appropriate preventive actions and aging detection activities will be performed for components exposed to fuel oil, lubricating oil, or located within closed cycle cooling water systems.

Exelon Response

The components exposed to a fuel oil environment which are included within the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are associated with the dirty fuel oil portion of the Emergency Diesel Generator system; specifically the dirty fuel oil drain tank and associated piping and valves. Since the dirty fuel oil components are beyond the boundary addressed by the GALL Report AMP XI.M30 Fuel Oil Chemistry program, the preventive measures within the Fuel Oil Chemistry program would not be effective to manage aging. The fuel oil environment associated with these components has similar attributes to the waste water environment, which is monitored by the Internal Surfaces in Miscellaneous Piping and Ducting Components program. This program includes visual inspection of metallic components that is effective in identifying loss of material due to corrosion. Therefore, the Internal Surfaces in Miscellaneous Piping and Ducting Components program is selected to manage these components so they are directly monitored by visual inspection to detect aging due to loss of material.

The components exposed to a lubricating oil environment which are included in the in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are the elastomer hoses in the lube oil portion of the Emergency Diesel Generator system. These components may indirectly benefit from the Lubricating Oil Analysis program; however, that program does not address aging effects associated with elastomer components, and as such they would not be effectively managed. The Internal Surfaces in Miscellaneous Piping and Ducting Components program includes visual inspection and manual manipulation of elastomer components that are effective in identifying hardening and loss of strength due to elastomer degradation. Therefore, the Internal Surfaces in Miscellaneous Piping and Ducting Components program is selected to manage these components so they are directly monitored by visual inspection augmented by physical manipulation where appropriate, to detect aging due to hardening and loss of strength. This is consistent with GALL Report AMP XI.M38 Scope of

Program description for the Internal Surfaces in Miscellaneous Piping and Ducting Components program, which states that "the program manages the effects of aging of polymer materials in all environments to which these materials are exposed".

The components exposed to a closed treated water environment which are included in the in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are the hoses in the jacket cooling water portion of the Emergency Diesel Generator system. GALL Report, Revision 2 includes AMR line item VII.C2.AP-259, which specifies that the Internal Surfaces in Miscellaneous Piping and Ducting Components program is to be used to manage hardening and loss of strength due to elastomer degradation of components in a closed-cycle cooling water environment. These components may also indirectly benefit from preventive measures within the Closed Treated Water Systems program; however, that program does not address aging effects associated with elastomer components, and as such they would not be effectively managed. The Internal Surfaces in Miscellaneous Piping and Ducting Components program includes visual inspection and manual manipulation of elastomer components that are effective in identifying hardening and loss of strength due to elastomer degradation. Therefore, the Internal Surfaces in Miscellaneous Piping and Ducting Components program is selected to manage these components so they are directly monitored by visual inspection augmented by physical manipulation where appropriate, to detect aging due to hardening and loss of strength. This is consistent with GALL Report AMP XI.M38 Scope of Program description for the Internal Surfaces in Miscellaneous Piping and Ducting Components program, which states that "the program manages the effects of aging of polymer materials in all environments to which these materials are exposed".

In summary, the preventive measures within the Fuel Oil Chemistry, Lubricating Oil Analysis, or Closed Treated Water Systems aging management programs are not applicable to managing the aging effects for the components discussed above. Since the Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program (LRA AMP B.2.1.26) includes performance of appropriate aging detection activities for the component/ material/ environment combinations involved, it is selected to manage those aging effects.

RAI B.2.1.29-1

Background

The program basis document for LRA AMP B.2.1.29, Buried and Underground Piping and Tanks, “preventive actions” program element states that the plant drainage system piping is neither coated nor cathodically protected, and the circulating water system piping is not coated. The applicable AMR items state that the components are constructed of steel. GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks,” Table 2a, recommends that buried steel piping be coated and cathodically protected.

Issue

The lack of cathodic protection and coatings for the plant drainage system and lack of coating for the circulating water system result in the LRA AMP B.2.1.29, Buried and Underground Piping and Tanks, not being consistent with the GALL Report “preventive actions” program element. The basis for this exception is not clear to the staff.

Request

State the basis for how the aging of buried components in the plant drainage and circulating water systems will be adequately managed such that their intended functions will be maintained consistent with the current licensing basis despite a lack of cathodic protection and coatings for the plant drainage system and lack of coating for the circulating water system.

Exelon Response

Upon further review it was determined that the plant drainage system and the circulating water system piping are coated and the program basis document for LRA AMP B.2.1.29, Buried and Underground Piping and Tanks will be revised.

The buried Plant Drainage System piping is coated with somastic, which is similar to coal tar, in accordance with Table 1 of NACE SP0169-2007 which is consistent with GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks". The design specification for cathodic protection does not require these lines to be cathodically protected because they are fabricated from cast iron, a corrosion-resistant material.

The buried Circulating Water System piping is coated with coal tar enamel. Coal tar is in accordance with Table 1 of NACE SP0169-2007 which is consistent with GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks".

RAI B.2.1.29-2

Background

The program basis document for LRA AMP B.2.1.29, Buried and Underground Piping and Tanks, “detection of aging effects” program element states that adverse conditions detected during inspections will be evaluated and the potential inspection expansion will be determined in accordance with the corrective action program. GALL Report AMP XI.M41, “Buried and Underground Piping and Tanks,” recommends that if adverse indications are detected, inspection sample sizes within the affected piping categories are doubled and if adverse indications are found in the expanded sample, the inspection sample size is again doubled, with the doubling of the inspection sample size continuing as necessary.

Issue

It is not clear to the staff that the LRA is consistent with the GALL Report because the inspection expansion as determined by the applicant’s corrective action program may not meet the quantities recommended in the GALL Report.

Request

State the basis for how the corrective action program inspection expansion size will be consistent with GALL Report AMP XI.M41, or state why the corrective action inspection expansion size will be sufficient to detect degradation prior to it causing an in-scope component to not be capable of meeting its current licensing basis function(s).

Exelon Response

The LGS Buried and Underground Piping and Tanks aging management program enhancement is revised to include criteria such that if adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, the inspection sample size is again doubled. This doubling of the inspection sample size continues as dictated by the corrective action program. This criterion is in accordance with GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks."

LRA Appendix A.2.1.29 and Appendix B.2.1.29 are revised to include the enhanced inspection expansion criteria as shown in Enclosure B. LRA Table A.5 item 29 is revised to include the enhanced inspection expansion criteria as shown in Enclosure C.

RAI B.2.1.29-3

Background

The cathodic protection design basis document states that the cathodic protection system is required to maintain an energized voltage of not less than 850 millivolts negative potential with respect to a copper-copper sulfate reference electrode. The GALL Report AMP XI.M41, “acceptance criteria” program element recommends that cathodic protection system soil to pipe potential acceptance criteria be consistent with NACE SP0169-2007. NACE SP0169-2007, Section 7.1.2.7 states that excessive levels of cathodic protection can cause external coating disbondment.

Issue

Given that neither LRA AMP B.2.1.29, Buried and Underground Piping and Tanks, nor the cathodic protection design basis document state an upper limit to the pipe to soil potential, it is not clear to the staff that annual cathodic protection survey results will be used to ensure that excessive levels of cathodic protection are not applied.

Request

State an upper limit acceptance criterion for pipe to soil potential measurements, and state the basis for using the stated value.

Exelon Response

The LGS Buried and Underground Piping and Tanks aging management program enhancement is revised to include a statement in the annual cathodic protection survey that if negative polarized potential exceeds -1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program.

The basis is found in Peabody's Control of Pipeline Corrosion, Second Edition 2001, NACE International The Corrosion Society on page 28 where is states that under some conditions, excessive amounts of cathodic protection current to a coated pipeline may damage the coating. This process is called cathodic disbondment. The current flow promotes water and ion

migration through the coating and an increase in the electrolyte pH at the pipe surface. If the polarized potential is sufficiently negative, hydrogen can also evolve in the form of gas bubbles on the pipe surface. All of these processes are detrimental to coatings and promote degradation and disbondment. The polarized potential at which significant damage to a coating occurs is a function of many factors, including the inherent resistance of the coating to degradation, the quality of the coating application, the soil conditions, and the pipeline temperature. "As a rule of thumb, off-potentials that are more negative than -1.1 V (Copper Sulfate Electrode) should be avoided to minimize coating degradation."

LRA Appendix A.2.1.29 and Appendix B.2.1.29 are revised to address excessive levels of cathodic protection as shown in Enclosure B. LRA Table A.5 item 29 is revised to address excessive levels of cathodic protection as shown in Enclosure C.

Enclosure B

LGS License Renewal Application Updates

Notes:

- Updated LRA Sections and Tables are provided in the same order as the RAI responses contained in Enclosure A.
- 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 ***bold italics*** for inserted text and strikethroughs for deleted text.
    - The only exception to this convention is the response to **RAI BWRVIP-1** because the entire content within Appendix C is new; therefore text is not shown in bold/italicized font.

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Section 3.0 and Tables 3.0-1, 3.0-2, 3.2.1, 3.2.2-6, 3.3.2-4, 3.3.2-9, and 3.3.2-16 are revised as follows:

3.0 AGING MANAGEMENT REVIEW RESULTS

This section provides the results of the aging management review for those structures and components identified in Section 2.0 as being subject to aging management review.

Descriptions of the internal and external service environments that were used in the aging management review to determine aging effects requiring management are included in Table 3.0-1, Limerick Internal Service Environments and Table 3.0-2, Limerick External Service Environments. The environments used in the aging management reviews are listed in the Environment column. The third column identifies one or more of the NUREG-1801 environments that were used when comparing the Limerick Aging Management Review results to the NUREG-1801 results. ***For cases where an internal environment may also be applicable as an external environment (e.g., for a component located within a heat exchanger), it is only listed on Table 3.0-1.***

Table 3.0-1 – Limerick Internal Service Environments

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Air/Gas-Dry	This environment includes air with a very limited percentage of moisture present that has been treated to reduce the dewpoint well below the system operating temperature. This includes air within air-conditioned spaces and it also includes commercial grade gases (such as nitrogen, freon, etc.) that are provided as a high quality product with little if any external contaminants. This environment does not include air within piping systems downstream of dryers because these dryers require a program to assure they remain functional. For these systems, the Air/Gas - Wetted environment is used.	Gas ~~Dried Air~~ ***Air, dry***

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Air/Gas-Wetted	Air/Gas environments containing significant amounts of moisture where condensation or water pooling may occur. This environment includes air with enough moisture to facilitate loss of material in steel caused by general, pitting, and crevice corrosion. Any internal air environment that does not meet the definition of Air/Gas – Dry (Internal) is to be categorized as Air/Gas – Wetted (Internal). This includes outdoor ***or indoor*** air drawn inside ventilation systems ***and air spaces within tanks***.	Condensation ~~Condensation (Internal)~~ ~~Moist air or condensation (internal)~~ ***Air, moist***
Closed Cycle Cooling Water	Closed Cycle Cooling Water includes treated water subject to the Closed Treated Water Systems program, which is Aging Management Program XI.M21A in NUREG-1801. The Closed Treated Water Systems program relies on maintenance of system corrosion inhibitor concentrations within specified limits of Electric Power Research Institute Technical Report 1007820 to minimize corrosion. Demineralized water is treated with corrosion inhibitors, pH control agents, or biocides, as needed.	Closed-cycle cooling water ~~Closed cycle cooling water >140°F~~
Diesel Exhaust	This environment represents the exhaust from diesel engines. It is considered to have the potential to concentrate contaminants and be subject to wetting through condensation.	Diesel Exhaust
Fuel Oil	This environment includes fuel oil for the Emergency Diesel Generators and Diesel-driven Fire Pump. Water contamination of fuel oil is assumed.	Fuel oil
Lubricating Oil	Lubricating oils are low to medium viscosity hydrocarbons used for bearing, gear, and engine lubrication, also functionally encompasses hydraulic oil (non water based). Water contamination of lubricating oil is assumed.	Lubricating oil

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Raw Water	The Schuylkill River and Perkiomen Creek, as well as, ground water from wells provide the sources of raw water utilized by LGS. Raw water is also rain or ground water. Raw water is water that has not been demineralized or treated to any significant extent.	~~Any~~ ***Condensation*** Raw water ~~Various~~
Reactor Coolant	Reactor coolant is demineralized water used within the Reactor Coolant System to transfer heat from the fuel inside the Reactor Vessel core. The Reactor Coolant environment also includes steam. This environment is used for the following systems for consistency with NUREG-1801 terminology: Reactor Vessel System, Reactor Vessel Internals System, and Reactor Coolant System. The temperature of the Reactor Coolant environment will always be assumed to be >482°F. The components in other systems that form a portion of the reactor coolant pressure boundary may use the Treated Water environment, which is functionally equivalent to the Reactor Coolant environment.	Reactor coolant Reactor coolant >250°C (>482°F) ~~Reactor coolant/steam~~ ***Reactor coolant and neutron flux*** ***Reactor coolant >250°C (>482°F) and neutron flux***
Reactor Coolant and Neutron Flux	The Reactor Coolant and Neutron Flux environment should be selected for components within the Reactor Vessel System and Reactor Vessel Internals System that are in contact with reactor coolant and are exposed to neutron fluence projected to exceed 1.0×10^{17} n/cm^2 (E >0.1 MeV) within 60 years. The temperature of the Reactor Coolant environment will always be assumed to be >482°F.	Reactor coolant and neutron flux Reactor coolant >250°C (>482°F) and neutron flux ~~Reactor Coolant and High Fluence (> 1×10^{21} n/cm^2 E>0.1 Mev)~~ Reactor coolant
Sodium Pentaborate Solution	Treated water that contains sodium pentaborate. This is confined to the SLC system at Limerick which is contained within a limited area of the secondary containment.	Sodium Pentaborate solution

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Steam	This is the internal environment associated with dry steam, such as Main Steam ***up to the main turbine***~~. This environment does not result in Flow-Accelerated Corrosion or Erosion.~~ The Water Chemistry Program is used for managing aging effects in dry steam environments, but the One-Time Inspection Program is not required by NUREG-1801. ~~Wet steam is included within the Treated Water environment, and is not to be called Steam.~~ Wet steam environments for LGS are ***typically*** described as either Treated Water or Reactor Coolant, depending upon location, ***but may utilize the NUREG-1801 steam environment for cumulative fatigue damage or loss of material aging effects***.	Steam ***Reactor coolant*** ***Treated water***
Treated Water	Treated water is demineralized water or chemically purified water and is the base water for all clean systems. Depending on the system, treated water may require further processing. Treated water may be deaerated and include corrosion inhibitors, biocides, or some combination of these treatments. The treated water environment also includes all wet steam environments.	Treated water ***Reactor coolant*** ~~Steam~~ ***Treated water <60°C (<140°F)*** ***Air – indoor, uncontrolled or Air – outdoor (applies to cumulative fatigue damage)***
Treated Water >140°F	The same as the Treated Water environment, except the Treated Water >140°F environment is to be selected for systems operating at temperatures >140°F that contain stainless steel components.	Treated water ***>60°C (***140°F***)*** Treated water ***Reactor coolant*** ~~Steam~~

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Treated Water >482°F	*a)* ***The same as the Treated Water environment, except the Treated Water >482°F environment is to be selected for systems operating at temperatures >482°F and that contain Cast Austenitic Stainless Steel (CASS) components.***	~~Treated water >482°F~~ Treated water ***>60°C (***>140°F***)*** Treated water Reactor Coolant ***>250°C (***>482°F***)*** ~~Steam~~
Waste Water	*b)* ***Radioactive, potentially radioactive, or non-radioactive waters that are collected from equipment and floor drains. Waste waters may contain contaminants, including oil, depending on location, as well as originally treated water that is not monitored by a chemistry program.***	Waste water
Waste Water >140°F	*c)* ***The same as the Waste Water environment, except the Waste Water >140°F environment is to be selected for systems operating at temperatures >140°F that contain stainless steel components.***	Waste water

Table 3.0-2 – Limerick External Service Environments

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Adverse Localized Environment	This environment represents conditions with excessive heat, radiation, moisture, or voltage, sometimes in the presence of oxygen. The effect can be concentrated or applicable to a general plant area. This environment is used for electrical commodities.	Adverse Localized Environment
Air – Indoor, Controlled	This environment is one to which the specified internal or external surface of the component or structure is exposed; a humidity-controlled (i.e., air conditioned) environment. For electrical purposes, control must be sufficient to eliminate the cited aging effects of contamination and oxidation without affecting the resistance. In general, at Limerick this environment should only be applied within the Control Room Envelope or inside certain HVAC ducts, plenums or other components.	Air – Indoor controlled
Air – Indoor, Uncontrolled	The Air - Indoor Uncontrolled (External) environment is for indoor locations that are sheltered or protected from weather. Humidity levels up to 100 percent are assumed and the surfaces of components in this environment ~~may~~ ***can*** be wet, ***but only rarely; equipment surfaces are normally dry***. ~~In addition, the NUREG-1801 environments defined for Air with Steam or Water Leakage are included within this environment description. This environment may contain aggressive chemical species including oxygen, halides, sulfates, or other aggressive corrosive substances that can influence the nature, rate, and severity of corrosion effects. It is assumed that these contaminants can concentrate to levels that will promote corrosive effects because of factors such as cyclic (wet-dry) condensation, contaminated insulation, accidental contamination, or leakage areas.~~	Air – indoor uncontrolled ~~Air – indoor uncontrolled (>95°F) (Internal/External)~~ ~~Air with steam or water leakage~~ ~~Air with leaking secondary-side water and/or steam~~ ~~Condensation (Internal or External)~~ ***System temperature up to 288°C (550°F) (applies to closure bolting)***

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Air with reactor coolant leakage	This environment is applicable to closure bolting only which is located in the vicinity of the RPV. The Air with reactor coolant or steam leakage environment is a high temperature leakage environment.	Air with reactor coolant leakage System temperature up to 288^{0}C (550^{0}F) ***(applies to closure bolting)*** ***Air***
Air – Outdoor	Air – Outdoor (External) is atmospheric air with a temperature range of -9°F to 107°F and a relative humidity range of 10% to 100%. This environment is subject to periodic wetting and wind.	~~Air - indoor and outdoor~~ ~~Air - indoor uncontrolled or air – outdoor~~ ~~Air - indoor uncontrolled or air outdoor~~ Air – outdoor ~~Air - outdoor (External)~~ ~~Any~~ ~~Underground~~ ~~Various~~
Concrete	This environment is one where components are embedded in concrete. This environment is considered aggressive if the concrete pH <11.5 or chlorides concentration >500 ppm.	Concrete ~~Buried~~

Limerick AMR Environment	Description	NUREG-1801 Environments Used For AMR Comparison
Encased in Steel	Concrete encased in steel is protected from environments that promote age related degradations. ~~The c~~***C***oncrete which is totally enclosed and contained within the inner, outer, sleeve, and cover steel plates of ***the*** Reactor Shield is an example of where the "encased in steel" environment is applied. The concrete which is encased in steel is protected from other environments that promote age-related degradation. ~~In the case of a steel lined concrete primary containment, the concrete covered by the steel liner is exempt from examination requirements, whereas other concrete surfaces which are exposed to other environments require examination. However, the encased in steel environment is not applied to a steel lined concrete primary containment since the concrete is not completely encased in steel and concrete surfaces exist which are exposed to other environments.~~	Environment not addressed in NUREG-1801
Groundwater/Soil	This is the external environment for components buried in the soil where there is groundwater in the soil.	Groundwater/Soil ***Soil*** ~~Buried~~ Water – flowing or standing
Soil	This is the external environment for components buried in the soil, and it includes ground water in the soil.	Soil ~~Buried~~
Water – flowing	Water that is refreshed, thus having larger impact on leaching; this can be raw water, groundwater, or flowing water under a foundation.	Water – flowing ~~Water – flowing under foundation~~
Water – standing	Water that is stagnant and unrefreshed, thus possibly resulting in increased ionic strength of solution up to saturation. This can be raw water or groundwater.	Water – standing

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Table 3.2.1, page 3.2-27, is revised as follows:

Table 3.2.1 Summary of Aging Management Evaluations for the Engineered Safety Features

Item Number	Component	Aging Effect/Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.2.1-56	Aluminum Piping, piping components, and piping elements exposed to Air-indoor uncontrolled (Internal/External)	None	None	NA - No AEM or AMP	Consistent with NUREG-1801.
3.2.1-57	Copper alloy Piping, piping components, and piping elements exposed to Air – indoor uncontrolled (External), Gas	None	None	NA - No AEM or AMP	Consistent with NUREG-1801.
3.2.1-58	PWR Only				
3.2.1-59	Galvanized steel Ducting, piping, and components exposed to Air – indoor controlled (External)	None	None	NA - No AEM or AMP	~~Consistent with NUREG-1801.~~ ***Not applicable.*** ***There are no galvanized steel ducting, piping, and components exposed to Air – indoor controlled in Engineered Safety Features systems.***
3.2.1-60	Glass Piping elements exposed to Air – indoor, uncontrolled (External), Lubricating oil, Raw water, Treated water, Treated water (borated), Air with borated water leakage, Condensation (Internal/External), Gas, Closed-cycle cooling water, Air – outdoor	None	None	NA - No AEM or AMP	Consistent with NUREG-1801.

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Table 3.2.2-6, page 3.2-69, is revised as follows:

Table 3.2.2-6
Standby Gas Treatment System
Summary of Aging Management Evaluation

Table 3.2.2-6 Standby Gas Treatment System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.B.E-40	3.2.1-40	A
					Bolting Integrity (B.2.1.11)	V.E.EP-70	3.2.1-13	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	V.E.EP-69	3.2.1-15	A
Ducting and Components	Pressure Boundary	Aluminum	Air - Indoor, Uncontrolled (External)	None	None	V.F.EP-3	3.2.1-56	C
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.F1.AP-142	3.3.1-92	C
		Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.B.E-26	3.2.1-40	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	V.D2.E-27	3.2.1-46	C
		Elastomer	Air - Indoor, Uncontrolled (External)	Hardening and Loss of Strength	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.B.EP-59	3.2.1-38	A
			Air/Gas - Wetted (Internal)	Hardening and Loss of Strength	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)			G
		Galvanized Steel	Air - Indoor, Uncontrolled (External)	None	None	~~V.F.EP-14~~ ***VII.J.AP-13***	~~3.2.1-59~~ ***3.3.1-116***	~~A~~ ***C***

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Table 3.3.2-4, page 3.3-99, is revised as follows:

Table 3.3.2-4
Control Enclosure Ventilation System
Summary of Aging Management Evaluation

Table 3.3.2-4 Control Enclosure Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Accumulator	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-22	3.3.1-120	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.F1.AP-99	3.3.1-94	C
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.F1.A-105	3.3.1-78	A
					Bolting Integrity (B.2.1.11)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VII.I.AP-124	3.3.1-15	A
		Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VII.I.AP-124	3.3.1-15	A
Ducting and Components	Leakage Boundary	Stainless Steel	Air/Gas - Wetted (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.F1.AP-99	3.3.1-94	A, 2
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.E5.AP-278	3.3.1-95	C
	Pressure Boundary	Aluminum	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-~~36~~ ***135***	3.3.1-113	C

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Table 3.3.2-4, page 3.3-108, is revised as follows:

Table 3.3.2-4 Control Enclosure Ventilation System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (MCR and AER Rm Humidifier Pan)	Leakage Boundary	Stainless Steel	Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.E5.AP-278	3.3.1-95	A
Valve Body	Leakage Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.13)	VII.C2.A-52	3.3.1-49	A
	Pressure Boundary	Aluminum	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-~~36~~ ***135***	3.3.1-113	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-37	3.3.1-113	A
		Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.D.A-80	3.3.1-78	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.13)	VII.F1.AP-202	3.3.1-45	A
		Copper	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.AP-143	3.3.1-89	A
		Copper Alloy with 15% Zinc or More	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.AP-143	3.3.1-89	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-22	3.3.1-120	A

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Table 3.3.2-9, page 3.3-145, is revised as follows:

Table 3.3.2-9 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.18)	VII.G.A-33	3.3.1-64	A
	Pressure Boundary	Aluminum	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-~~36~~ ***135***	3.3.1-113	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.18)	VII.G.AP-180	3.3.1-65	A
		Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
					Fire Protection (B.2.1.17)	VII.G.AP-150	3.3.1-58	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.H1.A-24	3.3.1-80	A
			Air/Gas - Dry (Internal)	None	None	VII.J.AP-6	3.3.1-121	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.A-23	3.3.1-89	A
			Diesel Exhaust (Internal)	Cumulative Fatigue Damage	TLAA			H, 7
				Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.H2.AP-104	3.3.1-88	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.20)	VII.H1.AP-105	3.3.1-70	A
					One-Time Inspection (B.2.1.22)	VII.H1.AP-105	3.3.1-70	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.18)	VII.G.A-33	3.3.1-64	A

As a result of the response to RAI 3.0.2-1 provided in Enclosure A of this letter, LRA Table 3.3.2-16, page 3.3-186, is revised as follows:

Table 3.3.2-16

Primary Containment Ventilation System

Summary of Aging Management Evaluation

Table 3.3.2-16 Primary Containment Ventilation System

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Bolting	Mechanical Closure	Carbon and Low Alloy Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.F3.A-105	3.3.1-78	A
					Bolting Integrity (B.2.1.11)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VII.I.AP-124	3.3.1-15	A
		Stainless Steel Bolting	Air - Indoor, Uncontrolled (External)	Loss of Material	Bolting Integrity (B.2.1.11)	VII.I.AP-125	3.3.1-12	A
				Loss of Preload	Bolting Integrity (B.2.1.11)	VII.I.AP-124	3.3.1-15	A
Ducting and Components	Leakage Boundary	Stainless Steel	Air/Gas - Wetted (External)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.F3.AP-99	3.3.1-94	A, 1
			Waste Water (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.E5.AP-278	3.3.1-95	C
	Pressure Boundary	Aluminum	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-~~36~~ ***135***	3.3.1-113	C
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.F3.AP-142	3.3.1-92	C
		Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.F3.A-10	3.3.1-78	A

As a result of the response to RAI BWRVIP-1 provided in Enclosure A of this letter, the LRA is revised to add Appendix C as shown below: (The entire content within Appendix C is new; therefore text is not shown in bold/italicized font.)

~~APPENDIX C~~

~~(This Appendix is not used).~~

APPENDIX C

Response to BWRVIP License Renewal Applicant Action Items

Of the BWRVIP reports credited within Limerick license renewal aging management programs, the following include NRC safety evaluation reports (SERs) that include action items applicable to license renewal applicants:

- BWRVIP-18 BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines (Revision 1)
- BWRVIP-25 BWR Core Plate Inspection and Flaw Evaluation Guidelines
- BWRVIP-26-A BWR Top Guide Inspection and Flaw Evaluation Guidelines
- BWRVIP-38 BWR Shroud Support Inspection and Flaw Evaluation Guidelines
- BWRVIP-41 BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (Revision 2)
- BWRVIP-42-A BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines
- BWRVIP-47-A BWR Lower Plenum Inspection and Flaw Evaluation Guidelines
- BWRVIP-48-A BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines (Credited in BWR Vessel ID Attachment Weld program)
- BWRVIP-49-A BWR Instrument Penetration Inspection and Flaw Evaluation Guidelines (Credited in BWR Penetrations program)
- BWRVIP-74-A BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guideline for License Renewal
- BWRVIP-76-A BWR Core Shroud Inspection and Flaw Evaluation Guidelines

License renewal applicant action items identified in the corresponding SERs for each of the above BWRVIP reports are addressed in the following tables. BWRVIP-27-A is not included because for Limerick the Standby Liquid Control System does not inject through the Core DP instrumentation reactor vessel penetration. BWRVIP reports without SERs for license renewal do not have action items and are therefore not included in the tables.

It is recognized that the first three action items from each of the license renewal SERs applicable to the above BWRVIP reports are fundamentally identical. For that reason they are combined in the table and addressed together.

Common Action Items from BWRVIP-18, -25, -26-A, -38, -41, 42-A, -47A, -48-A, -49-A, --74-A, -76-A	
Action Item Description	**LGS Response**
BWRVIP-All (1) The license renewal applicant is to verify that its plant is bounded by the report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP reports to manage the effects of aging of subject components during the period of extended operation. Applicants for license renewal will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the aging management programs within these BWRVIP reports described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the components or other information presented in the reports, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).	The BWRVIP reports applicable to LGS have been reviewed and LGS aging management programs have been verified to be bounded by the reports. Additionally, LGS is committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operations. These commitments are included in LRA Appendix A, Section A.5. If, upon review of a BWRVIP approved guideline, it is determined that known deviations to full compliance are warranted, the NRC will be notified of the deviation within 45 days of the receipt of NRC final approval of the guideline. Commitments are administratively controlled in accordance with the requirements of 10 CFR 50, Appendix B.
BWRVIP-All (2) 10 CFR 54.21(d) requires that an FSAR supplement for the facility contains a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAAs for the period of extended operation. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the programs and activities specified as necessary in the applicable BWRVIP reports are summarily described in the FSAR supplement.	The UFSAR supplements are included in LRA Appendix A. The FSAR supplements include a summary description of the programs and activities specified as necessary for managing the effects of aging per the BWRVIP reports.

Action Item Description	LGS Response
BWRVIP-All (3) 10 CFR 54.22 requires that each application for license renewal include any technical specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the renewal application. The applicable BWRVIP reports may state that there are no generic changes or additions to technical specifications associated with the report as a result of its aging management review and that the applicant will provide the justification for plant-specific changes or additions. Those applicants for license renewal referencing the applicable BWRVIP report shall ensure that the inspection strategy described in the reports does not conflict with or result in any changes to their technical specifications. If technical specification changes or additions do result, then the applicant must ensure that those changes are included in its application for license renewal.	There are no technical specification changes identified that are required to meet the requirements of the BWRVIP reports during the period of extended operation. Reference LRA Appendix D.
Additional Action Items	
BWRVIP-18 Core Spray Internals Inspection and Flaw Evaluation Guidelines	
Action Item Description	**LGS Response**
BWRVIP-18 (4) Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV core spray internal components.	There were no TLAA issues identified for core spray components that are internal to the reactor vessel.

BWRVIP-25 Core Plate Inspection and Flaw Evaluation Guidelines	
Action Item Description	**LGS Response**
BWRVIP-25 (4) Due to susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue.	Preload of the rim hold-down bolts is required to prevent lateral motion of the core plate for those plants that do not have core plate wedges installed. Stress relaxation of the RPV core plate rim hold-down bolts has been identified as a TLAA issue as evaluated in LRA Section 4.6.3.
BWRVIP-25 (5) Until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspections of the rim hold-down bolts.	The BWRVIP recognizes that it is not possible to implement meaningful inspections using the inspection methods recommended in BWRVIP-25. The BWRVIP is addressing this issue and intends to develop revised guidance. The BWRVIP recommendation to document deviation from BWRVIP-25 inspection guidelines of the core plate hold down bolts is currently being implemented. A BWRVIP Deviation Disposition is in place to implement the revised guidance prior to December 31, 2015, or until the NRC approves revised BWRVIP guidance, whichever occurs first. Therefore, inspection of the core plate rim hold down bolts will be in compliance with BWRVIP guidance prior to and through the period of extended operation.

BWRVIP-26-A Top Guide Inspection and Flaw Evaluation Guidelines	
Action Item Description	**LGS Response**
BWRVIP-26-A (4) Due to IASCC susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue.	The RAMA fluence evaluation for reactor internals performed for license renewal determined that the neutron fluence threshold for IASCC susceptibility has been exceeded. No TLAA has been identified. During the period of extended operation, the aging of the top guide will be managed by inspections conducted as part of the BWR Vessel Internals program per guidance provided in BWRVIP-183. The BWR Vessel Internals program requires that at least 10 percent of the grid beam cells containing control rod blades will be inspected every twelve years. The inspections are performed using the enhanced visual inspection technique, EVT-1. The program also allows for inspections to be performed using UT once it becomes available. Inspections will continue to be performed as described above during the period of extended operation.

BWRVIP-42-A BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines.	
Action Item Description	**LGS Response**
BWRVIP-42-A (4) Applicants referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internal components	There were no TLAA issues identified for the LPCI coupling.
BWRVIP-42-A (5) The BWRVIP committed to address development of the technology to inspect inaccessible welds and to have the individual LR applicant notify the NRC of actions planned. Applicants referencing BWRVIP-42 report for license renewal should identify the action as open and to be addressed once the BWRVIP's response to this issue has been reviewed and accepted by the staff.	Inspection of the LPCI coupling is performed in accordance with guidelines described in BWRVIP-42. There are no inaccessible welds associated with the LPCI Couplings.

BWRVIP-47-A, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines	
Action Item Description	**LGS Response**
BWRVIP-47-A (4) Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue.	Fatigue usage is considered a TLAA for reactor vessel internals, including lower plenum components. This is addressed in LRA Section 4.3.4.

BWRVIP-74-A , BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines	
Action Item Description	**LGS Response**
BWRVIP-74-A (4) The staff is concerned that leakage around the reactor vessel seal rings could accumulate in the VFLD lines, cause an increase in the concentration of contaminants and cause cracking in the VFLD line. The BWRVIP-74 report does not identify this component as within the scope of the report. However, since the VFLD line is attached to the RPV and provides a pressure boundary function, LR applicants should identify an AMP for the VFLD line.	The vessel flange leak detection (VFLD) nozzle and piping is included in the scope of scope of license renewal. Cracking of the vessel flange leak detection nozzle is managed by the ASME Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry programs. Cracking of the VFLD piping is managed by the One-Time Inspection of ASME Code Class 1 Small-Bore Piping, Water Chemistry, and ASME Inservice Inspection, Subsections IWB, IWC, and IWD programs. Reference LRA Section 3.1.2.2.4.
BWRVIP-74-A (5) LR applicants shall describe how each plant-specific aging management program addresses the following elements: (1) scope of program, (2) preventative actions, (3) parameters monitored and inspected, (4) detection of aging effects, (5) monitoring and trending, (6) acceptance criteria, (7) corrective actions, (8) confirmation process, (9) administrative controls, and (10) operating experience.	There are no plant-specific aging management programs credited for managing aging of reactor pressure vessel components. Descriptions of the aging management programs credited for managing the reactor pressure vessel are described in Appendix B. These descriptions include any program element that deviates from the NUREG-1801 program element, and any enhancements that are required to meet NUREG-1801 requirements.

Action Item Description	LGS Response
BWRVIP-74-A (6) The staff believes inspection by itself is not sufficient to manage cracking. Cracking can be managed by a program that includes inspection and water chemistry. BWRVIP-29 describes a water chemistry program that contains monitoring and control guidelines for BWR water that is acceptable to the staff. BWRVIP-29 is not discussed in the BWRVIP-74 report. Therefore, in addition to the previously discussed BWRVIP reports, LR applicants shall contain water chemistry programs based on monitoring and control guidelines for reactor water chemistry that are contained in BWRVIP-29.	The Water Chemistry aging management program (B.2.1.2) is consistent with NUREG-1801, Revision 2 program, XI.M2, "Water Chemistry" and meets the requirements of the latest BWRVIP Water Chemistry guidelines (BWRVIP-190) to help ensure the long-term integrity of the reactor vessel and internals. Aging management programs that utilize inspections to perform condition monitoring of reactor pressure vessel and internal components to identify cracking also credit the Water Chemistry program to mitigate cracking of reactor vessel components, including BWR Vessel Internals, BWR Vessel ID Attachment Welds, BWR Penetrations, and BWR Stress Corrosion Cracking programs.
BWRVIP-74-A (7) LR applicants shall identify their vessel surveillance program, which is either an ISP or plant-specific in-vessel surveillance program, applicable to the LR term.	The Reactor Vessel Surveillance program (B.2.1.21) is an Integrated Surveillance Program (ISP) for the license renewal term.
BWRVIP-74-A (8) LR applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue usage is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a LR applicant must address environmental fatigue for the components listed in the BWRVIP-74 report for the LR period.	The Reactor Vessel Internals Fatigue Analyses are evaluated as TLAAs in LRA Section 4.3.4. Transient cycle projections demonstrate that current transient cycle limits will not be exceeded during the period of extended operation. Environmental fatigue for reactor vessel components is addressed in LRA Section 4.3.3 with results shown in Table 4.3.3-1.

Action Item Description	LGS Response
BWRVIP-74-A (9) Appendix A to the BWRVIP-74 report indicates that a set of P-T curves should be developed for the heat-up and cool-down operating conditions in the plant at a given EFPY in the LR period.	P-T limit curves will be developed per 10 CFR 50, Appendix G requirements for the period of extended operation as described in LRA Section 4.2.4.
BWRVIP-74-A (10) To demonstrate that the beltline materials meet the Charpy USE criteria specified in Appendix B of the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.	Charpy upper-shelf energy (USE) values for the period of extended operation were determined using methods consistent with RG 1.99, Revision 2. This is described as a TLAA in LRA Section 4.2.2 with results shown in Tables 4.2.2-1 and 4.2.2-2.
BWRVIP-74-A (11) To obtain relief from the in-service inspection of the circumferential welds during the LR period, the BWRVIP report indicates each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in the Appendix E for the staff's July 28, 1998, SER, and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.	At the end of the renewal period, the circumferential welds for each unit will satisfy the limiting conditional failure frequency for circumferential welds in the staff's July 28, 1998, FSER. The discussion of the relief from the in-service inspection of the circumferential welds during the period of extended operation is described in LRA Section 4.2.6 with results shown in Table 4.2.6-1.

Action Item Description	LGS Response
BWRVIP-74-A (12) As indicated in the staff's March 7, 2000, letter to Carl Terry, a LR applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine that the mean RT_{NDT} of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of this FSER.	Axial Weld Inspection is discussed as a TLAA in LRA Section 4.2.5. The mean RT_{NDT} of the limiting axial beltline weld for each unit at the end of the period of extended operation is less than the value specified in Table 1 of BWRVIP-74-A FSER as shown in LRA Table 4.2.5-1.
BWRVIP-74-A (13) The Charpy USE, P-T limit, circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using staff approved methodology or may submit the methodology for staff review. If the applicant performs the neutron fluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.	An NRC approved methodology was used to determine fluence during the period of extended operation, as discussed in LRA Section 4.2.1. The RAMA Methodology used was approved within the SER for BWRVIP-114, 115, 117 and 121.
BWRVIP-74-A (14) Components that have indications that have been previously analytically evaluated in accordance with sub-section IWB-3600 of Section XI to the ASME Code until the end of the 40-year service period shall be re-evaluated for the 60-year service period corresponding to the LR term.	A flaw in the Unit 1 RPV nozzle to safe-end weld VRR-1RD-1A-N2H was analytically evaluated in accordance with ASME Code Section XI, sub-section IWB-3600. Prior to the period of extended operation, this condition will be re-evaluated for the 60-year service period corresponding to the LR term. If subsequent flaw evaluations are performed on other RPV components, they will be evaluated for acceptability for the LR term.

BWRVIP-76-A , BWR Core Shroud Inspection and Flaw Evaluation Guidelines	
Action Item Description	**LGS Response**
BWRVIP-76-A (4) The applicant shall reference the NRC staff-approved TRs BWRVIP-14-A, BWRVIP-99 (when approved) and BWRVIP-100-A in their RVI AMP. The applicant shall make a statement in their LRA that the crack growth rate evaluations and fracture toughness values specified in these reports shall be used for cracked core shroud welds that are exposed to the neutron fluence values that are specified in these TRs. The applicant shall confirm that they will incorporate any emerging inspection guidelines developed by the BWRVIP for these welds.	The BWR Vessel Internals AMP implements BWRVIP-76-A requirements including guidance within BWRVIP-76-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The current guidance references BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100-A for fracture toughness values. The BWR Vessel Internals AMP includes reference to BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A for evaluation of crack growth. The implementing procedure for the BWR Vessel Internals AMP includes guidance to incorporate new guidance within new or revised BWRVIP reports. This assures that any emerging inspection guidelines developed by the BWRVIP for these core shroud welds will be incorporated into the program.
BWRVIP-76-A (5) LR applicants that have core shrouds with tie rod repairs shall make a statement in their AMP associated with RVI components that they have evaluated the implications of the Hatch Unit 1 tie rod repair cracking on their units and incorporated revised inspection guidelines, if any, developed by the BWRVIP.	The core shrouds have not been modified to include tie rod repairs.

Action Item Description	LGS Response
BWRVIP-76-A (6) The NRC staff's guidance in Table IV.B1 of the GALL Report lists two potentially applicable aging effects (i.e., in addition to cracking) for generic BWR reactor vessel internal components (including BWR core shroud and core shroud repair assembly components) that are made from either stainless steel (including CASS) or nickel alloy: (1) loss of material due to pitting and crevice corrosion (Refer to GALL AMR IV.B1-15), and cumulative fatigue damage (Refer to AMR Item IV.B1-14). BWR LR applicants will need to assess their designs to see if the generic guidelines for managing cumulative fatigue damage in GALL AMR item IV.B1-14 and for management of loss of material due to pitting and crevice corrosion in GALL AMR IV.B1-15 are applicable to the design or their core shroud components (including welds) and any core shroud assembly components that have been installed through a design modification of the plant. If these aging affects are applicable to the design of these components as a result of exposing them to a reactor coolant with integrated neutron flux environment, applicants for license renewal will need to: (1) identify the aging effects as aging effects requiring management (AERM) for the core shrouds and for their core shroud assembly components if a repair design modification has been implemented, and (2) identify the specific aging management programs or time-limited aging analyses that will be used to manage these aging effects during the period of extended operation. Refer to License Renewal Applicant Action Item 7) for additional guidance on identifying the AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy.	The core shrouds (including welds) are fabricated from stainless steel or nickel alloy. In addition to cracking, loss of material due to pitting and crevice corrosion and cumulative fatigue damage are identified as aging effects requiring aging management review applicable to the core shroud design. The BWR Vessel Internals and Water Chemistry aging management programs will be used to manage loss of material due to pitting and crevice corrosion during the period of extended operation. TLAA is used to manage cumulative fatigue damage for the core shroud as discussed in the application LRA Section 4.3.4.

Action Item Description	LGS Response
BWRVIP-76-A (7) For BWR LRAs identification of AERMs for core shroud components or core shroud repair assembly components that are made from materials other than stainless steel (including CASS) or nickel alloy will need to be addressed on a plant specific basis that is consistent with the Note format criteria for plant-specific AMR items in the latest NRC-approved version TR NEI-95-10.	The core shrouds (including welds) are fabricated from stainless steel or nickel alloy. No core shroud repair assembly components have been added. Therefore, there is no need to address core shroud components that are made from materials other than stainless steel or nickel alloy.
BWRVIP-76-A (8) LR applicant shall reference the NRC staff-approved topical reports BWRVIP-99 and BWRVIP-100-A in their RVI components AMP.	The BWR Vessel Internals AMP implements BWRVIP-76-A requirements including guidance within BWRVIP-76-A Section D to use current NRC-approved BWRVIP guidance to determine crack growth rates and fracture toughness values. The current guidance references BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100-A for fracture toughness values. The BWR Vessel Internals AMP includes reference to BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A for evaluation of crack growth.

As a result of the response to RAI B.2.1.2-1 provided in Enclosure A of this letter, the Water Chemistry aging management program, Section A.2.1.2 of the LRA, is revised as shown below:

A.2.1.2 Water Chemistry

The Water Chemistry aging management program is an existing program whose activities consist of monitoring and control of water chemistry to manage the aging of reactor vessel, reactor internals, piping, piping elements and piping components, heat exchangers and tanks that are exposed to treated water. The Water Chemistry aging management program keeps peak levels of various contaminants below system-specific limits based on ***the*** industry recognized guidelines of ***the Boiling Water Reactor Vessel and Internals Project (BWRVIP-190, Electric Power Research Institute - 1016579)*** ~~EPRI, BWR Vessel and Internals Project BWR Water Chemistry Guidelines~~ for the prevention or mitigation of loss of material, reduction of heat transfer and cracking aging effects. In addition, the water chemistry program is also credited for mitigating loss of material and cracking for components exposed to sodium pentaborate, steam and reactor coolant environments. To mitigate aging effects on component surfaces the chemistry program is used to control water chemistry for impurities that accelerate corrosion.

As a result of the response to RAI B.2.1.3-1 provided in Enclosure A of this letter, the Reactor Head Closure Stud Bolting Program, LRA Section A.2.1.3 and B.2.1.3, is revised as shown below:

A.2.1.3 Reactor Head Closure Stud Bolting

The Reactor Head Closure Stud Bolting program is an existing program that provides for condition monitoring and preventive activities to manage reactor head closure studs and associated nuts, ~~bushings,~~ washers and flange threads for cracking and loss of material. The program is implemented through station procedures based on the examination and inspection requirements specified in ASME Section XI, Table IWB-2500-1 and preventive measures described in NRC Regulatory Guide 1.65, "Materials and Inspection for Reactor Vessel Closure Studs~~.~~"***, with the exception that stud bolting material having a measured yield stress greater than 150 ksi is used.***

B.2.1.3 Reactor Head Closure Stud Closure

Program Description

The Reactor Head Closure Stud Bolting aging management program is an existing condition monitoring and preventive program that provides for ASME Section XI inspections of reactor head closure studs and associated nuts, ~~bushings,~~ flange threads, and washers for cracking and loss of material. The Reactor Head Closure Stud Bolting program manages these aging effects in air with reactor coolant leakage environment. The frequency of monitoring is adequate to prevent significant degradation. The program is based on the examination and inspection requirements specified in the ASME Section XI Code, Subsection IWB, Table IWB-2500-1, and preventive measures described in NRC Regulatory Guide ***(RG)*** 1.65, "Materials and Inspection for Reactor Vessel Closure Studs."

The current ISI Program plan for the third ten-year inspection interval (February 1, 2007 through January 31, 2017) is based on the 2001 ASME Code, Section XI, including 2003 addenda. The future 120-month inspection intervals will incorporate the requirements specified in the version of the ASME Code incorporated into 10 CFR 50.55a twelve months before the start of the inspection interval.

The Reactor Head Closure Stud Bolting program implements ASME Section XI inspection requirements through the ISI Program plan. The inspections monitor for cracking, loss of material, and coolant leakage.

The program uses visual and volumetric examinations in accordance with the general requirements of Section XI, Subsection IWA-2000. The Reactor Head Closure Stud Bolting program was developed in accordance with the requirements detailed in the ASME Code, Section XI, Division 1, Subsections IWA, IWB, Mandatory Appendices and Inspection Program B of IWA-2432.

ASME Section XI allows for a number of examination methods to be used for volumetric and visual inspections. The flange threads and studs receive a volumetric examination and the surfaces of nuts and washers are inspected using a VT-1 examination. All pressure-retaining boundary components in Examination Category B-P receive a visual VT-2 examination during the system leakage test and the system hydrostatic test.

The extent and schedule for examining and testing the reactor head closure studs, nuts, ~~bushings,~~ flange threads, and washers is specified in Table IWB-2500-1 for B-G-1 components, “Pressure Retaining Bolting Greater than 2 Inches in Diameter.”

Indications and relevant degraded conditions detected during examinations are evaluated in accordance with ASME Section XI Subsection IWB-3100 for Class 1 components by comparing ISI results with the acceptance standards of IWB-3400 and IWB-3500. Specifically, flaw indications or relevant degraded conditions are evaluated in accordance with IWB-3515 or IWB-3517 as indicated in Table IWB-2500-1 and Table 3410-1 of ASME Section XI.

The reactor head closure studs are constructed of ASME SA540 Grade B24, Class 3 material, which has a maximum tensile strength of less than 170 ksi, which complied with RG 1.65 Revision 0 which was current during plant construction. The Reactor Head Closure Stud Bolting program includes the preventive measures to mitigate cracking described in ~~the NRC Regulatory Guide~~***RG*** 1.65, which includes the use of approved corrosion inhibitors and lubricants. The reactor head closure studs, nuts, ~~bushings, flange threads,~~ and washers are fabricated with ~~approved materials and surface treated with~~ an acceptable phosphate coating to inhibit corrosion ~~and reduce SCC and IGSCC~~. In addition, a stable lubricant that does not contain molybdenum disulfide is applied to the nuts, threads and all bearing surfaces of the nuts and washers prior to reactor vessel head re-installation.

~~The reactor head closure studs are constructed of ASME SA540 Grade B24, Class 3 material, which has a maximum tensile strength of less than 170 ksi. This complies with the NRC Regulatory Guide 1.65.~~

As a result of the response to RAI B.2.1.3-1 provided in Enclosure A of this letter, the following Exception to NUREG-1801 and Justification for Exception are being added to LRA Section B.2.1.3, Reactor Head Closure Stud Bolting as shown below:

Exceptions to NUREG-1801

~~None~~

1. ***NUREG-1801 requires, as a preventive measure that can reduce the potential for SSC, using bolting material for closure studs that has an actual measured yield strength limited to less than 1,034 megapascals (MPa) (150 kilo-pounds per square inch) (NUREG-1339). Certified Material Test Reports (CMTRs) obtained for reactor head closure studs installed prior to commercial operation, or used as replacements, include test data indicating that all installed studs may have actual measured yield strength that is greater than 150 ksi. Program Element Affected: Preventive Measures (Element 2)***

Justification for Exception

The reactor head closure studs are fabricated from SA 540 Grade B24 carbon steel, which has a minimum yield stress of 130 ksi. Relative to material strength, the studs are in compliance with RG 1.65 Revision 0, which was current during plant construction. RG 1.65 required the studs to have a maximum measured tensile strength of 170 ksi. The maximum reported ultimate tensile strength for the installed studs is 164 ksi for Unit 1 and 169 ksi for Unit 2. RG 1.65, Revision 1 describes SA 540 Grade B24 as high-strength, low alloy material that when tempered to a maximum tensile strength of less than 170 ksi, is relatively immune to stress corrosion cracking. Therefore, the installed studs were consistent with the existing regulatory guidance when installed, and are relatively immune to stress corrosion cracking.

The CMTR data for the installed studs indicates that it is possible that all installed studs may have measured yield strength above 150 ksi; however the average measured yield strength for the heats used for all but four of the studs are less than 150 ksi. The average measured yield strength for the heat used for four Unit 2 studs was 152.1 ksi, with a maximum reported test result of 157 ksi. The CMTR data indicates that the installed studs have measured yield strength that is at most marginally above NUREG-1801 criteria for measured yield strength.

All other preventive measures listed in NUREG-1801 program XI.M3, Reactor Head Closure Stud Bolting that can reduce the potential for cracking are met.

a) ***Metal-plated stud bolting is not used, which could cause degradation due to corrosion or hydrogen embrittlement;***
b) ***A phosphate surface treatment was applied to the studs, nuts and washers during fabrication to inhibit corrosion;***
c) ***An approved stable lubricant is applied to the studs and associated hardware whenever the reactor head installed. The lubricant used does not contain molybdenum disulfide (MoS_2) which has been shown to be a potential contributor to SCC and should not be used.***

An additional preventive measure has been implemented to revise the purchasing requirements for RPV head studs to assure that any studs installed in the future have a measured yield strength less than 150 ksi as reported on CMTRs.

Since the actual measured yield strength of the installed studs may be greater than 150 ksi, the aging management review identified the stud material as "High Strength Low Alloy Steel Bolting with Yield Strength of 150 ksi or Greater". This resulted in identifying cracking as an aging effect requiring management. The volumetric (UT) examination method in place for stud inspection per ASME Section XI, Table IWB-2500-1, Category B-G-1, and required per the program, is appropriate for identifying cracking. There have been no recordable indications identified by Inservice Inspection program examination of reactor head closure stud bolting components over the past ten years, indicating that the current program has been effective in managing cracking. Therefore the Reactor Head Closure Stud Bolting aging management program will be effective in managing the cracking aging effect during the period of extended operation.

As a result of the response to RAIs B.2.1.7-2 and B.2.1.7-3 provided in Enclosure A of this letter, UFSAR Supplement LRA Section A.2.1.7 is revised as shown below:

A.2.1.7 BWR Stress Corrosion Cracking

The BWR Stress Corrosion Cracking aging management program is an existing augmented Inservice Inspection program that manages intergranular stress corrosion cracking (IGSCC) in reactor coolant pressure boundary piping and piping components made of stainless steel and nickel based alloy***, regardless of code classification,*** as delineated in NUREG-0313, Revision 2, and NRC Generic Letter 88-01 and its Supplement 1. The program includes preventive measures to mitigate IGSCC, and inspection and flaw evaluation to monitor IGSCC and its effects. The schedule and extent of the inspections are performed in accordance with the NRC staff-approved BWRVIP-75-A report for normal water chemistry conditions~~, and staff-approved EPRI Topical Report TR-112657, Revision B-A, Final Report, "Risk-Informed Inservice Inspection Evaluation Procedure," December 1999~~.

As a result of the responses to RAI B.2.1.11-1 and RAI B.2.1.11-2 provided in Enclosure A of this letter, the Bolting Integrity program, Section A.2.1.11 and Section B.2.1.11 of the LRA, is revised as shown below:

A.2.1.11 Bolting Integrity

The Bolting Integrity aging management program is an existing program that provides for aging management for loss of material***, cracking,*** and loss of preload of pressure retaining bolted joints within the scope of license renewal. 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," as part of the comprehensive component pressure retaining bolting program. The program provides for managing loss of material***, cracking,*** and loss of preload by performing visual inspections ***of*** ~~for~~ ***safety-related*** pressure retaining bolted joint***s*** ~~leakage~~ at least once per refueling cycle ***for leakage, loss of material, cracking, and loss of preload. Bolting for other pressure retaining components is inspected for signs of leakage.*** Inspection activities for bolting in a submerged environment are performed in conjunction with component maintenance activities. Inspection activities for bolting in buried and underground applications is performed in conjunction with inspection activities for the Buried and Underground Piping and Tanks (A.2.1.29) aging management program due to the restricted accessibility to these locations.

B.2.1.11 BOLTING INTEGRITY

Program Description

The Bolting Integrity aging management program is an existing condition monitoring and preventive program that provides for aging management for loss of material***, cracking,*** and loss of preload of pressure retaining bolted joints within the scope of license renewal. The program includes bolting in air-indoor, air-outdoor, air-indoor with reactor coolant leakage, air/gas wetted, treated water, raw water, and soil environments. 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," as part of the comprehensive component pressure retaining bolting program. The program provides for managing loss of material***, cracking,*** and loss of preload by performing visual inspections ~~for~~ ***of safety-related*** pressure retaining bolted joint***s*** ~~leakage~~ at least once per refueling cycle ***for leakage, loss of material, cracking, and loss of preload.*** Inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities. Inspection activities for bolting in buried and underground applications is performed in conjunction with inspection activities for the Buried and Underground Piping and Tanks (B.2.1.29) program due to the restricted accessibility to these locations.

The ISI program plan tables provide the examination category and description as identified in ASME Section XI, Table IWB-2500-1 for Class 1 components, Table IWC-2500-1 for Class 2 components, and Table IWD-2500-1 for Class 3 components.

Examinations are currently performed in accordance with the ASME Section XI, 2001 Edition through the 2003 Addenda, per the ISI program plan. Examinations for the period of extended operation will be in accordance with the appropriate code edition and addenda for the ISI program plan. In accordance with 10 CFR 50.55a(g)(4)(ii), the program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval. The extent and schedule of the inspections is in accordance with IWB-2500-1, IWC-2500-1, and IWD-2500-1 and assures that detection of leakage or fastener degradation occurs prior to loss of system or component intended functions. Bolting associated with Class 1 vessel, valve and pump flanged joints receive visual (VT-1) inspection. For other pressure retaining bolting, routine observations identify any leakage before the leakage becomes excessive.

The integrity of non-ASME Class 1, 2, or 3 system and component bolted joints is evaluated by detection of visible leakage during maintenance or routine observation such as system walkdowns and inspections at least once per refueling cycle. Inspection activities for non-ASME Class 1, 2, or 3 bolting in a submerged environment are performed in conjunction with associated component maintenance activities.

The Corrective Action Program is used to document and manage those locations where ***degradation or*** leakage was identified during routine observations including engineering walkdowns and equipment maintenance activities. Based on the severity of the leak and the potential to impact plant operations, nuclear or industrial safety, a leak may be repaired immediately, scheduled for repair, or monitored for change. If the leak rate changes (increases, decreases, or stops), the monitoring frequency is re-evaluated and may be revised.

High strength bolts (actual yield strength ≥150 ksi) are not used on pressure retaining bolted joints within the scope of the Bolting Integrity aging management program.

Procurement controls and installation practices, defined in plant procedures, include preventive measures to ensure that only approved lubricants, sealants, and proper torque are applied. The activities are implemented through station procedures. Lubricants containing molybdenum disulfide are not used.

As a result of the responses to RAI B.2.1.12-1 and RAI B.2.1.12-2 provided in Enclosure A of this letter, the Open-Cycle Cooling Water program, Section A.2.1.12 and Section B.2.1.12 of the LRA, is revised as shown below:

A.2.1.12 Open-Cycle Cooling Water System

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing program that manages heat exchangers, piping, piping elements and piping components in safety-related and nonsafety-related raw water systems that are exposed to raw water and air/gas-wetted environments for loss of material, reduction of heat transfer, and hardening and loss of strength of elastomers. This is accomplished through tests and inspections per the guidelines of NRC Generic Letter 89-13. System and component testing, visual inspections, non-destructive examination (i. e. Radiographic Testing, Ultrasonic Testing and Eddy Current Testing), and chemical injection are conducted to ensure that aging effects are managed such that system and component intended functions and integrity are maintained.

The OCCWS includes those systems that transfer heat from safety-related structures, systems and components to the ultimate heat sink as defined in GL 89-13 as well as those raw water systems which are in scope for license renewal for spatial interaction but have no safety-related heat transfer function. Periodic heat transfer testing or inspection and cleaning of heat exchangers with a heat transfer intended function is performed in accordance with LGS commitments to GL 89-13 to verify heat transfer capabilities. Heat exchangers which have no safety-related heat transfer function are periodically inspected and cleaned.

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

1. Perform internal inspection of buried Safety Related Service Water Piping when it is accessible during maintenance and repair activities

2. Perform periodic inspections for loss of material in the Nonsafety-Related Service Water System at a ~~frequency in accordance with NRC Generic Letter 89-13.~~ ***minimum of five locations on each unit once every refueling cycle.***

3. ***Replace the supply and return piping for the Core Spray pump compartment unit coolers.***

4. ***Replace degraded RHRSW piping in the pipe tunnel.***

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

B.2.1.12 Open-Cycle Cooling Water System

Enhancements

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

1. Perform internal inspection of buried Safety Related Service Water Piping when it is accessible during maintenance and repair activities. **Program Elements Affected: Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4)**

2. Perform periodic inspections for loss of material in the Nonsafety-Related Service Water System at a ~~frequency in accordance with NRC Generic Letter 89-13.~~ ***minimum of five locations on each unit once every refueling cycle.*** **Program Elements Affected: Parameters Monitored/Inspected (Element 3), Detection of Aging Effects (Element 4)**

3. ***Replace the supply and return piping for the Core Spray pump compartment unit coolers. Program Elements Affected: Preventive Actions (Element 2)***

4. ***Replace degraded RHRSW piping in the pipe tunnel. Program Elements Affected: Preventive Actions (Element 2)***

As a result of the response to RAI B.2.1.13-2 provided in Enclosure A of this letter, LRA Table 3.3.2-2, page 3.3-91, for the Closed Cooling Water System is revised as follows:

Table 3.3.2-2 Closed Cooling Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.G.A-23	3.3.1-89	A
			Closed Cycle Cooling Water (Internal)	Loss of Material	Closed Treated Water Systems (B.2.1.13)	VII.C2.AP-189	3.3.1-46	C
								H, 1

Plant Specific Notes:

~~None.~~

1. ***The loss of material due to cavitation erosion has been identified in reactor enclosure cooling water piping to the 2A Reactor Water Cleanup System (RWCU) non-regenerative heat exchanger. This aging effect/mechanism is not in NUREG-1801 for either carbon steel or the closed cycle cooling water environment. The Closed Treated Water Systems (B.2.1.13) program, which has been enhanced to include periodic NDE, will be used to manage the loss of material due to cavitation erosion.***

As a result of the response to RAIs B.2.1.15-1 and B.2.1.15-2 provided in Enclosure A of this letter Compressed Air Monitoring program, LRA Section A.2.1.15, is revised as follows:

A.2.1.15 COMPRESSED AIR MONITORING

The Compressed Air Monitoring aging management program is an existing program that manages piping, piping components, piping elements, and valve bodies for loss of material in the compressed air systems. The Compressed Air Monitoring aging management activities consist of air quality monitoring and trending, preventive maintenance, and condition monitoring measures to manage the aging effects.

The Compressed Air Monitoring program is based on the LGS response to NRC Generic letter 88-14, "Instrument Air Supply Problems" and utilizes guidance and standards provided in INPO SOER 88-01. The Compressed Air Monitoring program activities implement the moisture and contaminant criteria of ANSI MC11.1 (ISA S7.3, incorporated into ANSI/ISA-S7.0.01). Program activities include air quality checks at various locations to ensure that dew point, particulates, lubricant content and contaminants are maintained within the specified limits.

The Compressed Air Monitoring Program will be enhanced to:

1. Perform periodic analysis and trending of air quality monitoring results.

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

As a result of the response to RAI B.2.1.15-1 provided in Enclosure A of this letter, Compressed Air Monitoring program, LRA Section B.2.1.15 is revised as follows:

B.2.1.15 COMPRESSED AIR MONITORING

NUREG-1801 Consistency

The Compressed Air Monitoring aging management program ~~is~~ ***will be*** consistent with the ten elements of aging management program XI.M24, "Compressed Air Monitoring," specified in NUREG-1801.

Exceptions to NUREG-1801

None.

Enhancements

~~None.~~

Prior to the period of extended operation, the following enhancement will be implemented in the following program element:

1. ***Perform periodic analysis and trending of air quality monitoring results. Program Element Affected: Monitoring and Trending (Element 5)***

Conclusion

The ~~existing~~ ***enhanced*** Compressed Air Monitoring program ***will*** provide~~s~~ reasonable assurance that the loss of material aging effect will be adequately managed so that the intended functions of components within the scope of license renewal are maintained consistent with the current licensing basis during the period of extended operation.

As a result of the response to RAI B.2.1.17-1 provided in Enclosure A of this letter, LRA section 3.3.2.1.9 is revised as shown below:

3.3.2.1.9 Fire Protection System

Materials

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

- ***Alumina Silica***
- Aluminum
- Cafecote
- Carbon Steel
- Carbon and Low Alloy Steel Bolting
- Cement
- Concrete
- Copper Alloy with 15% Zinc or More
- Copper Alloy with less than 15% Zinc
- Darmatt
- Ductile Cast Iron
- Elastomer
- Galvanized Steel
- Glass
- Gray Cast Iron
- Grout
- ***Gypsum***
- Polymer
- Soil (Asphalt covered)
- Stainless Steel
- Thermolag

As a result of the response to RAI B.2.1.17-1 provided in Enclosure A of this letter, LRA Table 3.3.1, page 3.3-55, is revised as shown below:

Table 3.3.1 Summary of Aging Management Evaluations for the Auxiliary Systems

Item Number	Component	Aging Effect/ Mechanism	Aging Management Programs	Further Evaluation Recommended	Discussion
3.3.1-57	Elastomers Fire barrier penetration seals exposed to Air - indoor, uncontrolled, Air – outdoor	Increased hardness; shrinkage; loss of strength due to weathering	Chapter XI.M26, "Fire Protection"	No	Consistent with NUREG-1801. The Fire Protection (B.2.1.17) program will be used to manage hardening***,*** and loss of strength in elastomer fire barrier penetration seals ***and fire stops*** exposed to air-indoor, uncontrolled in the Fire Protection System. The Structures Monitoring (B.2.1.35) program has been substituted and will be used to manage increased hardness, shrinkage, and loss of strength in elastomer expansion joints and seismic gap fillers exposed to air-indoor, uncontrolled and air-outdoor in the Admin Building Shop and Warehouse, Auxiliary Boiler and Lube Oil Storage Enclosure, Control Enclosure, Emergency Diesel Generator Enclosure, Primary Containment, Radwaste Enclosure, Reactor Enclosure, Service Water Pipe Tunnel, Spray Pond and Pump House, Turbine Enclosure, and Yard Facilities.
3.3.1-58	Steel Halon/carbon dioxide fire suppression system piping, piping components, and piping elements exposed to Air – indoor, uncontrolled (External)	Loss of material due to general, pitting, and crevice corrosion	Chapter XI.M26, "Fire Protection"	No	Consistent with NUREG-1801. The Fire Protection (B.2.1.17) program will be used to manage the loss of material in carbon steel halon/carbon dioxide fire suppression piping, piping components, and piping elements, and tanks exposed to air-indoor, uncontrolled in the Fire Protection System.

As a result of the response to RAI B.2.1.17-1 provided in Enclosure A of this letter, LRA Table 3.3.2-9, pages 3.3-143 and 3.3-154, is revised as shown below:

Table 3.3.2-9 Fire Protection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Fire Barriers (For steel components)	Fire Barrier	Cafecote	Air - Indoor, Uncontrolled (External)	Cracking	Fire Protection (B.2.1.17)			F, 3
				Loss of Material	Fire Protection (B.2.1.17)			F, 3
Fire Barriers (Penetration Seals ***and Fire Stops***)	Fire Barrier	***Alumina Silica***	***Air - Indoor, Uncontrolled (External)***	***Cracking***	***Fire Protection (B.2.1.17)***			***F, 9***
		Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	Fire Protection (B.2.1.17)	VII.I.A-77	3.3.1-78	E, 2
		Elastomer	Air - Indoor, Uncontrolled (External)	Hardening and Loss of Strength	Fire Protection (B.2.1.17)	VII.G.A-19	3.3.1-57	A
		Grout	Air - Indoor, Uncontrolled (External)	Cracking and spalling	Fire Protection (B.2.1.17)	VII.G.A-90	3.3.1-60	A, 4
					Structures Monitoring (B.2.1.35)	VII.G.A-90	3.3.1-60	A, 4
Fire Barriers (Walls and Slabs)	Fire Barrier	Concrete	Air - Indoor, Uncontrolled (External)	Concrete cracking and spalling	Fire Protection (B.2.1.17)	VII.G.A-90	3.3.1-60	A
					Structures Monitoring (B.2.1.35)	VII.G.A-90	3.3.1-60	A
				Loss of Material	Fire Protection (B.2.1.17)	VII.G.A-91	3.3.1-62	A
					Structures Monitoring (B.2.1.35)	VII.G.A-91	3.3.1-62	A
			Air - Outdoor (External)	Concrete cracking and spalling	Fire Protection (B.2.1.17)	VII.G.A-92	3.3.1-61	A
					Structures Monitoring (B.2.1.35)	VII.G.A-92	3.3.1-61	A
				Loss of Material	Fire Protection (B.2.1.17)	VII.G.A-93	3.3.1-62	A
					Structures Monitoring (B.2.1.35)	VII.G.A-93	3.3.1-62	A
		Gypsum	***Air - Indoor, Uncontrolled (External)***	***Cracking***	***Fire Protection (B.2.1.17)***			***F, 8***
Fire Hydrant	Pressure Boundary	Gray Cast Iron	Air - Outdoor (External)	Loss of Material	Fire Water System (B.2.1.18)	VII.G.AP-149	3.3.1-63	A

Plant Specific Notes:

1. This component is a soil dike covered with asphalt, intended to contain oil spills. The aging effects are similar to those of GALL item III.A6.T-22 for Earthen water-control structures. The Structures Monitoring (B.2.1.35) program is credited with managing the aging effects for this component.

2. The Fire Protection (B.2.1.17) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

3. Darmatt, Thermolag, and Cafecote are fire-resistant insulation and coating materials potentially subject to cracking and loss of material. The Fire Protection (B.2.1.17) program manages the aging of these materials.

4. NUREG-1801 does not contain grout fire barriers, however cracking and spalling are applicable aging effects for both grout and concrete materials, and are managed for grout fire barriers by the Fire Protection (B.2.1.17) and Structures Monitoring (B.2.1.35) programs.

5. Cement lined piping is used for the buried fire loop main. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

6. The Foam Solution Tank contents is a commercial chemical foam-generating solution that is mixed with water for use. Since it is not controlled by the Water Chemistry (B.2.1.2) program, it has been classified as a Raw Water environment.

7. This component is associated with carbon steel diesel driven Fire Water Pump engine exhaust piping in a diesel exhaust environment. TLAA is used to manage the aging effect(s) applicable to this component type, material and environment combination. The TLAA designation in the Aging Management Program column indicates that fatigue of this component is evaluated in Section 4.3.

8. This component is a gypsum wall which has a fire barrier intended function. The Fire Protection (B.2.1.17) program will be used to manage the identified aging effects for this component, material and environment combination.

9. The Fire Protection (B.2.1.17) program will be used to manage the identified aging effects for this component, material and environment combination.

As a result of the responses to RAI B.2.1.19-1 and RAI B.2.1.19-2 provided in Enclosure A of this letter, the Aboveground Metallic Tanks program, Section A.2.1.19 and Section B.2.1.19 of the LRA, is revised as shown below:

A.2.1.19 Aboveground Metallic Tanks

The Aboveground Metallic Tanks aging management program is an existing program that manages the loss of material aging effect of the Backup Water Storage Tank. Paint is a corrosion preventive measure, and periodic visual inspections will monitor degradation of the paint and any resulting metal degradation of metallic tanks.

The Aboveground Metallic Tanks aging management program will be enhanced to:

1. Include UT measurements of the bottom of the Backup Water Storage Tank. Tank bottom UT inspections will be performed ***within five years prior to entering the period of extended operation and every five years thereafter. If no tank bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed*** whenever the tank is drained during the period of extended operation. ~~and within five years prior to entering the period of extended operation.~~

2. Provide visual inspections of the Backup Water Storage Tank external surfaces and include, on a sampling basis, removal of insulation to permit inspection of the tank surface. ***An inspection performed prior to entering the period of extended operation will include a minimum of 25 locations to demonstrate that the tank painted surface is not degraded under the insulation.*** ~~The~~ ***Subsequent*** tank external surface visual inspection will be conducted on a two-year frequency ***and include a minimum of four locations.***

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

B.2.1.19 ABOVEGROUND METALLIC TANKS

Enhancements

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

1. Include UT measurements of the bottom of the Backup Water Storage Tank. Tank bottom UT inspections will be performed ***within five years prior to entering the period of extended operation and every five years thereafter. If no tank bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed*** whenever the tank is drained during the period of extended operation. ~~and within five years prior to entering the period of extended operation.~~ **Program Elements Affected: Scope of Program (Element 1), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6).**

2. Provide visual inspections of the Backup Water Storage Tank external surfaces and include, on a sampling basis, removal of insulation to permit inspection of the tank surface. ***An inspection performed prior to entering the period of extended operation will include a minimum of 25 locations to demonstrate that the tank painted surface is not degraded under the insulation.*** ~~The~~ ***Subsequent*** tank external surface visual inspection will be performed on a two-year frequency ***and include a minimum of four locations***. **Program Elements Affected: Scope of Program (Element 1), Preventive Actions (Element 2), Detection of Aging Effects (Element 4), Monitoring and Trending (Element 5), Acceptance Criteria (Element 6).**

As a result of the response to RAI B.2.1.25-1 provided in Enclosure A of this letter, LRA Sections 3.2.2.2.6, 3.3.2.2.3, and 3.4.2.2.2 are revised as follows:

3.2.2.2.6 Cracking due to Stress Corrosion Cracking

Item Number 3.2.1-7 is not applicable to LGS. ~~Stress corrosion cracking (SCC) is a mechanism requiring a tensile stress, a corrosive environment, and a susceptible material in order to occur. Outdoor air is assumed to be an aggressive environment having the potential for the concentration of contaminants that could promote SCC.~~ For the ESF Systems, there are no ***stainless steel*** components exposed to an outdoor air environment. Therefore, SSC is not applicable for ESF Systems at LGS.

3.3.2.2.3 Cracking due to Stress Corrosion Cracking

Item Number 3.3.1-4 is not applicable to LGS. ~~Stress corrosion cracking (SCC) is a mechanism requiring a tensile stress, a corrosive environment, and a susceptible material in order to occur. Outdoor air is assumed to be an aggressive environment having the potential for the concentration of contaminants that could promote SCC. However, SCC of stainless steels exposed to outdoor air is considered plausible only if the material temperature is above 140°F. For the Auxiliary Systems, the outdoor stainless steel components are < 140ºF.~~ ***The Limerick site is located more than 80 miles from the coast of the Atlantic Ocean. The major transportation routes near the site are at least one mile from this site. Although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant. A review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components. Recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition. Therefore, the outside air at LGS is not conducive to stress corrosion cracking, and*** ~~Therefore,~~ SSC is not applicable for stainless steel surfaces in an outdoor air environment in Auxiliary Systems at LGS.

3.4.2.2.2 Cracking due to Stress Corrosion Cracking (SCC)

Item Number 3.4.1-2 is not applicable to LGS. ~~Stress corrosion cracking (SCC) is a mechanism requiring a tensile stress, a corrosive environment, and a susceptible material in order to occur. SCC of stainless steels exposed to outdoor air and contaminants is considered plausible only if the material temperature is above 140 degrees F. For the Steam and Power Conversion systems, the outdoor stainless steel components are less than 140 degrees F.~~ ***The Limerick site is located more than 80 miles from the coast of the Atlantic Ocean. The major transportation routes near the site are at least one mile from this site. Although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant. A review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components. Recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition. Therefore, the outside air at LGS is not conducive to stress corrosion cracking, and*** ~~Therefore,~~ SCC is not applicable for stainless steel surfaces in an outdoor air environment in Steam and Power Conversion systems at LGS.

As a result of the response to RAI B.2.1.25-1 provided in Enclosure A of this letter, LRA Tables 3.3.2-8, 3.3.2-22, 3.4.2-1, and 3.4.2-2 are revised as follows:

Table 3.3.2-8, page 3.3-132:

Table 3.3.2-8 Emergency Diesel Generator 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	Ductile Cast Iron	Fuel Oil (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	VII.H1.AP-105	3.3.1-70	A
		Glass	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-14	3.3.1-117	A
			Air/Gas - Wetted (Internal)	None	None	VII.J.AP-97	3.3.1-117	A
			Closed Cycle Cooling Water (Internal)	None	None	VII.J.AP-166	3.3.1-117	A
			Lubricating Oil (Internal)	None	None	VII.J.AP-15	3.3.1-117	A
			Raw Water (Internal)	None	None	VII.J.AP-50	3.3.1-117	A
		Gray Cast Iron	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.27)	VII.H2.AP-127	3.3.1-97	A
					One-Time Inspection (B.2.1.22)	VII.H2.AP-127	3.3.1-97	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.H2.AP-221	3.3.1-6	A
				None	***None***	***VII.H2.AP-209***	***3.3.1-4***	***I, 6***
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.E5.AP-273	3.3.1-95	A
			Diesel Exhaust (Internal)	Cracking	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.H2.AP-128	3.3.1-83	A

Table 3.3.2-8, page 3.3-141:

5. These components are associated with the engine exhaust silencer drain piping. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26) program is substituted to manage the aging effect(s) applicable to this component type, material and environment combination.
6. ***Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.***

Table 3.3.2-22, page 3.3-230:

Table 3.3.2-22 Safety Related Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Pressure Boundary	Carbon Steel	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-183	3.3.1-38	C
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.C3.AP-198	3.3.1-106	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.A-54	3.3.1-40	A
Pump Casing	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
			Air/Gas - Wetted (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.G.A-23	3.3.1-89	E, 2
			Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-183	3.3.1-38	C
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-183	3.3.1-38	C
Spray Nozzles	Spray	Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.C3.AP-221	3.3.1-6	A
				None	***None***	***VII.C3.AP-209***	***3.3.1-4***	***I, 3***
			Air/Gas - Wetted (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.D.AP-81	3.3.1-56	E, 2
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.A-54	3.3.1-40	A
Valve Body	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.I.A-77	3.3.1-78	A
			Air - Outdoor (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.H1.A-24	3.3.1-80	E, 1
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-183	3.3.1-38	C

Table 3.3.2-22, page 3.3-231:

Table 3.3.2-22 Safety Related Service Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-17	3.3.1-120	A
			Air - Outdoor (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.C3.AP-221	3.3.1-6	E, 1
				None	***None***	***VII.C3.AP-209***	***3.3.1-4***	***I, 3***
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.A-54	3.3.1-40	A

Table 3.3.2-22, page 3.3-232:

Notes	Definition of Note
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1. The Buried and Underground Piping and Tanks (B.2.1.29) program is substituted to manage the aging effect applicable to this component type, material, and environment combination.

2. The Open-Cycle Cooling Water System (B.2.1.12) program is substituted to manage the aging effect applicable to this component type, material, and environment combination.

3. ***Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.***

Table 3.4.2-1, page 3.4-30:

Table 3.4.2-1 Circulating Water System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Piping, piping components, and piping elements	Leakage Boundary	Glass	Air - Indoor, Uncontrolled (External)	None	None	VIII.I.SP-9	3.4.1-55	A
			Raw Water (Internal)	None	None	VIII.I.SP-34	3.4.1-55	A
		Stainless Steel	Air - Indoor, Uncontrolled (External)	None	None	VIII.I.SP-12	3.4.1-58	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VIII.F.SP-117	3.4.1-21	C
	Pressure Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VIII.H.S-29	3.4.1-34	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VIII.E.SP-146	3.4.1-19	C
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VIII.E.SP-145	3.4.1-47	A
Strainer (Element)	Filter	Carbon Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VII.H1.A-24	3.3.1-80	A
			Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VIII.E.SP-146	3.4.1-19	C
		Polymer	Air - Outdoor (External)	None	None			G, 3
			Raw Water (External)	None	None			G, 3
		Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VIII.E.SP-127	3.4.1-3	A
				None	***None***	***VIII.E.SP-118***	***3.4.1-2***	***I, 4***
			Raw Water (External)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VIII.F.SP-117	3.4.1-21	C
Valve Body	Leakage Boundary	Carbon Steel	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VIII.H.S-29	3.4.1-34	A
			Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VIII.E.SP-146	3.4.1-19	C

Table 3.4.2-1, page 3.4-32:

Notes	Definition of Note
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

1. Stainless steel bolting materials in Air - Outdoor (External) and Raw Water (External) environments are associated with the cooling tower basin removable screens.

2. The Bolting Integrity (B.2.1.11) program is substituted to manage the aging effect(s) applicable to this component type, material, and environment combination.

3. Component material is fiber-reinforced plastic. Fiber-reinforced plastic, corresponding to the NUREG-1801 material of PVC, has no aging effects in Air - Outdoor (External), consistent with NUREG-1801 item VIII.I.SP-152 for PVC material in an Air - indoor, uncontrolled environment. Fiber-reinforced plastic, corresponding to PVC, also has no aging effects in the Raw Water environment, consistent with NUREG-1801 item VIII.I.SP-153 for PVC in the Condensation environment.

4. ***Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.***

Table 3.4.2-2, page 3.4-35:

Table 3.4.2-2 Condensate System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Valve Body	Pressure Boundary	Stainless Steel	Air - Outdoor (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	VIII.E.SP-127	3.4.1-3	A
				None	***None***	***VIII.E.SP-118***	***3.4.1-2***	***I, 1***
			Treated Water (Internal)	Loss of Material	One-Time Inspection (B.2.1.22)	VIII.E.SP-87	3.4.1-16	A
					Water Chemistry (B.2.1.2)	VIII.E.SP-87	3.4.1-16	A

Table 3.4.2-2, page 3.4-36:

Notes	Definition of Note
A	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
B	Consistent with NUREG-1801 item for component, material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
C	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP is consistent with NUREG-1801 AMP.
D	Component is different, but consistent with NUREG-1801 item for material, environment, and aging effect. AMP takes some exceptions to NUREG-1801 AMP.
E	Consistent with NUREG-1801 item for material, environment and aging effect, but a different aging management program is credited or NUREG-1801 identifies a plant-specific aging management program.
F	Material not in NUREG-1801 for this component.
G	Environment not in NUREG-1801 for this component and material.
H	Aging effect not in NUREG-1801 for this component, material and environment combination.
I	Aging effect in NUREG-1801 for this component, material and environment combination is not applicable.
J	Neither the component nor the material and environment combination is evaluated in NUREG-1801.

Plant Specific Notes:

~~None.~~

1. Based on LGS environmental conditions and verified by operating experience review, cracking is not an applicable aging effect for LGS outdoor components. The LGS outdoor environment is not conducive to stress corrosion cracking.

As a result of the response to RAI B.2.1.26-1 provided in Enclosure A of this letter, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, LRA Section A.2.1.26 and Section B.2.1.26 are revised as follows:

A.2.1.26 Inspection of Internal Surfaces In Miscellaneous Piping And Ducting Components

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that directs visual inspections of internal surfaces of components be performed when they are made accessible during maintenance activities. The program consists of visual inspections of metallic and elastomeric components such as piping, piping elements and piping components, ducting components, tanks, heat exchangers, elastomers and other components within the scope of license renewal. This program will manage the aging effects of loss of material***, loss of fracture toughness, reduction of heat transfer, and cracking*** for metallic ~~and elastomeric~~ components, and ***loss of material and*** hardening and loss of strength for elastomers. The program includes provisions for visual inspections of the internal surfaces of components not managed under other aging management programs, augmented by physical manipulation of flexible elastomers where appropriate.

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

B.2.1.26 Inspection of Internal Surfaces In Miscellaneous Piping And Ducting Components

Program Description

The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components aging management program is a new condition monitoring program that manages the aging of the internal surfaces of metallic and polymeric piping, piping elements and piping components, ducting components, tanks, heat exchangers, elastomers, and other components. This program will manage the aging effects of loss of material**, *loss of fracture toughness, reduction of heat transfer, and cracking*** for metallic ~~and elastomeric~~ components, and ***loss of material and*** hardening and loss of strength for elastomers, in air/gas wetted, closed cycle cooling water, diesel exhaust, fuel oil, lube oil, raw water, treated water, and waste water environments. The program includes provisions for visual inspections of the internal surfaces of components not managed under other aging management programs, augmented by physical manipulation of flexible elastomers where appropriate. Inspections will be performed when the internal surfaces are accessible during the performance of periodic surveillances, during maintenance activities, and during scheduled outages.

As a result of the response to RAIs B.2.1.29-2 and B.2.1.29-3 provided in Enclosure A of this letter, the Enhancement descriptions provided in LRA Section A.2.1.29 and Section B.2.1.29 are revised as follows:

A.2.1.29 Buried and Underground Piping and Tanks

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

1. ~~Evaluate adverse indications and potential inspection expansion, as part of the corrective action program, whenever inspections are performed.~~ ***If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, the inspection sample size is again doubled. This doubling of the inspection sample size continues as dictated by the corrective action program.***

7. Modify the yearly cathodic protection survey acceptance criterion to meet NACE SP0169-2007 standards ***and add a statement that if negative polarized potential exceeds -1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program.***

As a result of the response to RAIs B.2.1.29-2 and B.2.1.29-3 provided in Enclosure A of this letter, the Buried and Underground Piping and Tanks aging management program for Section B.2.1.29 of Appendix B, enhancement 1 on LRA page B-117 and enhancement 7 on LRA page B-118 is revised as shown below:

B.2.1.29 Buried and Underground Piping and Tanks

Enhancements

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

1. ~~Evaluate adverse indications and potential inspection expansion, as part of the corrective action program, whenever inspections are performed.~~ ***If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, the inspection sample size is again doubled. This doubling of the inspection sample size continues as dictated by the corrective action program.*** **Program Element Affected: Detection of Aging Effects (Element 4)**

7. Modify the yearly cathodic protection survey acceptance criterion to meet NACE SP0169-2007 standards ***and add a statement that if negative polarized potential exceeds -1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program.*** **Program Elements Affected: Preventative Actions (Element 2), Detection of Aging Effects (Element 4) and Acceptance Criteria (Element 6)**

Enclosure C

LGS License Renewal Commitment List Changes

This Enclosure includes an update to the LGS LRA Appendix A, Section A.5 License Renewal Commitment List, as a result of the Exelon response to the following RAIs:

RAI BWRVIP-1
RAI B.2.1.12-1
RAI B.2.1.12-2
RAI B.2.1.15-1
RAI B.2.1.19-1
RAI B.2.1.19-2
RAI B.2.1.29-2
RAI B.2.1.29-3

Note: For clarity, portions of the original LRA License Renewal Commitment List text are repeated in this Enclosure. Added text is shown in ***Bold Italics***.

As a result of the response to RAI BWRVIP-1 provided in Enclosure A of this letter, LRA Appendix A, Table A-5, License Renewal Commitment List is revised as shown

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
47	***BWRVIP-74-A Report License Renewal Action Item 14***	***Re-evaluate the flaw in the Unit 1 RPV nozzle to safe-end weld VRR-1RD-1A-N2H in accordance with ASME Code Section XI, sub-section IWB-3600 for the 60-year service period corresponding to the LR term.***	***Prior to the period of extended operation***	***LGS Letter, dated 2/15/12*** ***RAI BWRVIP-1***

As a result of the responses to RAI B.2.1.12-1 and RAI B.2.1.12-2 provided in Enclosure A of this letter, Table A.5 of the LRA is revised as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
12	Open-Cycle Cooling Water System	Open-Cycle Cooling Water System is an existing program that will be enhanced to: 1. Perform internal inspection of buried Safety Related Service Water Piping when it is accessible during maintenance and repair activities. ***2.*** Perform periodic inspections for loss of material in the Nonsafety-Related Service Water System at a ~~frequency in accordance with NRC Generic Letter 89-13~~. ***minimum of five locations on each unit once every refueling cycle.*** ***3. Replace the supply and return piping for the Core Spray pump compartment unit coolers.*** ***4. Replace degraded RHRSW piping in the pipe tunnel.***	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.12 ***LGS Letter dated 2/15/12*** ***RAI B.2.1.12-1*** ***RAI B.2.1.12-2***

As a result of the response to RAI B.2.1.15-1 provided in Enclosure A of this letter, LRA Table A.5, page A-51, is revised as follows:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
14	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to: 1. Perform annual periodic inspections as defined in the appropriate ASME B30 series standard for all cranes, hoists, and equipment handling systems within the scope of license renewal. For handling systems that are infrequently in service, such as those only used during refueling outages, annual periodic inspections may be deferred until just prior to use. 2. Perform inspections of structural components and bolting for loss of material due to corrosion, rails for loss of material due to wear and corrosion, and bolted connections for loss of preload. 3. Evaluate loss of material due to wear or corrosion and any loss of bolting preload on cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard. 4. Perform repairs to cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard.	Program to be enhanced prior to the period of extended operation.	Section A.2.1.14
15	Compressed Air Monitoring	***Compressed Air Monitoring is an*** ~~E~~***e***xisting program ***that will be enhanced to:***~~is credited.~~ ***1. Perform periodic analysis and trending of air quality monitoring results.***	~~Ongoing~~ ***Program to be enhanced prior to the period of extended operation.***	Section A.2.1.15 ***LGS letter dated 2/15/12*** ***RAI B.2.1.15-1***
14	BWR Reactor Water Cleanup System	Existing program is credited.	Ongoing	Section A.2.1.16

As a result of the responses to RAI B.2.1.19-1 and RAI B.2.1.19-2 provided in Enclosure A of this letter, LRA Table A.5, page A-52, is revised as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
19	Aboveground Metallic Tanks	Aboveground Metallic Tanks is an existing program that will be enhanced to: 1. Include UT measurements of the bottom of the Backup Water Storage Tank. Tank bottom UT inspections will be performed ***within five years prior to entering the period of extended operation and every five years thereafter. If no tank bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed*** whenever the tank is drained during the period of extended operation. ~~and within five years prior to entering the period of extended operation~~ 2. Provide visual inspections of the Backup Water Storage Tank external surfaces and include, on a sampling basis, removal of insulation to permit inspection of the tank surface. ***An inspection performed prior to entering the period of extended operation will include a minimum of 25 locations to demonstrate that the tank painted surface is not degraded under the insulation.*** ~~The~~ ***Subsequent*** tank external surface visual inspection will be conducted on a two year frequency ***and include a minimum of four locations***.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.19 ***LGS Letter dated 2/15/12*** ***RAI B.2.1.19-1*** ***RAI B.2.1.19-2***

As a result of the response to RAIs B.2.1.29-2 and B.2.1.29-3 provided in Enclosure A of this letter for the Buried and Underground Piping and Tanks aging management program, LRA Table A.5 Commitment List, commitment 29, item 1 on LRA page A-55 and item 7 on LRA page A-56, is revised as shown below:

A.5 License Renewal Commitment List

NO.	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
29	Buried and Underground Piping and Tanks	Buried and Underground Piping and Tanks is an existing program that will be enhanced to: 1. ~~Evaluate adverse indications and potential inspection expansion, as part of the corrective action program, whenever inspections are performed.~~ ***If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, the inspection sample size is again doubled. This doubling of the inspection sample size continues as dictated by the corrective action program.*** 7. Modify the yearly cathodic protection survey acceptance criterion to meet NACE SP0169-2007 standards ***and add a statement that if negative polarized potential exceeds -1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program.***	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.29 ***LGS Letter dated 2/15/12*** ***RAI B.2.1.29-2*** ***RAI B.2.1.29-3***