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10 CFR 50
10 CFR 51
10 CFR 54

March 14, 2014

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: Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555 and ME6556)

References:
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 John W. Lubinski (NRC) to Michael P. Gallagher (Exelon), "Safety Evaluation Report Related To The License Renewal of Limerick Generating Station, Units 1 and 2", dated January 10, 2013
3. Letter from Richard A. Plasse (NRC) to Michael P. Gallagher (Exelon) "Requests for Additional Information for the review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555 and ME6556)", dated February 10, 2014
4. Exelon Generation Company, LLC letter from Michael P. Gallagher to NRC Document Control Desk, "Review of Interim Staff Guidance LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation" dated March 12, 2014

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 U.S. Nuclear Regulatory Commission issued the Safety Evaluation Report related to the LGS LRA. In the reference 3 letter the NRC requested additional information to support the staff's review of the LRA. The reference 4 letter makes changes to some of the same sections of the LRA affected by this letter

Enclosure A contains the response to this request for additional information.

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

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

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

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

Executed on 3-14-2014

Respectfully,

Michael P. Gallagher

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

Enclosures: A: Response to Request for Additional Information
B: Updates to affected LRA sections
C: 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- DORL Limerick Generating Station
NRC Senior Resident Inspector, Limerick Generating Station
R. R. Janati, Commonwealth of Pennsylvania

Enclosure A

Response to Request For Additional Information Related to Coatings Associated with the LGS License Renewal Application (LRA)

RAI 3.0.3-1

RAI 3.0.3-1

Background:

The staff has noted several recent industry operating experience (OE) events related to loss of coating integrity of internal coatings. This has resulted in the staff concluding that several Aging Management Programs (AMP) and Aging Management Review (AMR) items in the License Renewal Application (LRA) may not or do not account for this OE.

Issue:

Loss of coating integrity for Service Level III (augmented) coatings:

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

For purposes of this RAI, Service Level III (augmented) coatings include:

1. Those installed on the interior of in-scope piping, heat exchangers, and tanks which support functions identified under 10 CFR 54.4(a)(1) and (a)(2).

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

The term "coating" includes inorganic (e.g., zinc-based) or organic (e.g., elastomeric or polymeric) coatings, linings (e.g., rubber, cementitious), and concrete surfacers (e.g., concrete-lined fire water system piping. The terms "paint" and "linings" should be considered as coatings.

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

1. Baseline visual inspections of coatings installed on the interior surfaces of in-scope components should be conducted in the 10-year period prior to the period of extended operation.
2. Subsequent periodic inspections where the interval is based on the baseline inspection results. For example:
    a. If no peeling, delamination, blisters, or rusting are observed, and any cracking and flaking has been found acceptable, subsequent inspections could be conducted after multiple refueling outage intervals (e.g., for example six years, or more if the same coatings are in redundant trains and turbulent flow is not a concern).
    b. If the inspection results do not meet the above; but, a coating specialist has determined that no remediation is required, subsequent inspections could be conducted every other refueling outage interval.
    c. If coating degradation is observed that required repair or replacement, or for newly installed coatings, subsequent inspections should occur at least once during the next two refueling outage intervals to establish a performance trend on the coatings.

3. All accessible internal surfaces for tanks and heat exchangers should be inspected. A representative sample of internally coated piping components not less than 73 one-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination should be inspected.
4. Coatings specialists and inspectors should be qualified in accordance with an ASTM International standard endorsed in RG 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Power Plants,” including staff guidance associated with a particular standard.
5. Monitoring and trending should include pre-inspection reviews of previous inspection results.
6. The acceptance criteria should include that indications of peeling and delamination are not acceptable. Blistering can be evaluated by a coating specialist; however, physical testing should be conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface.

Request:

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

1. the inspection method
2. the parameters to be inspected
3. when inspections will commence and the frequency of subsequent inspections
4. the extent of inspections and the basis for the extent of inspections if it is not 100 percent
5. the training and qualification of individuals involved in coating inspections
6. how trending of coating degradation will be conducted
7. acceptance criteria
8. corrective actions for coatings that do not meet acceptance criteria, and
9. the program(s) that will be augmented to include the above activities.

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

Exelon Response

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

(1) Reactor Enclosure Cooling Water (RECW) Heat Exchangers
(2) Main Control Room (MCR) Chiller Condenser
(3) Circulating Water System piping
(4) Cement lined portions of the Fire Water System piping (buried yard mains)
(5) Emergency Diesel Generator Diesel Oil Storage Tanks
(6) Reactor Core Isolation Cooling System (RCIC) turbine bearing pedestals and High Pressure Coolant Injection System (HPCI) turbine bearing pedestals and oil reservoir
(7) Galvanized portions of the Fire Water System (transformer deluge system piping; foam extinguishing system piping)
(8) Galvanized portions of the Plant Drainage System (normal waste, oily waste, sanitary waste and storm drain piping)
(9) Fire Water System Backup Water Storage Tank

Item number (7): Coating inspection is not required for the transformer deluge system and foam extinguishing system galvanized piping. These water-based subsystems are susceptible to age-related degradation. However, galvanized piping is not subject to unanticipated or accelerated corrosion of the base metal due to coating holidays. The unanticipated or accelerated aging postulated in the *Issue* section of this RAI is valid for most non-sacrificial coating systems since the coating forms a large cathode that is coupled with a small anode where a coating holiday exists. As described in *Corrosion Engineering*, Third Edition (M. A. Fontana), a large cathode surface and a small anode surface (e.g., due to a coating holiday) forms a strong galvanic cell (in an aqueous solution) that leads to accelerated corrosion of the smaller anode. However, in the case of galvanized steel, since zinc has a lower electrode potential than steel, the roles are reversed, with the zinc coating acting as a large sacrificial anode coupled with a small cathode where the steel substrate is exposed in the coating holiday. In certain specific situations (e.g., high temperatures) the galvanized coating can act as an anode, but those situations do not exist in the Fire Protection System. Since there is a relatively small cathode surface and a relatively large anode surface, there is no accelerated corrosion. In fact, the remaining zinc acts as a sacrificial anode to the base metal and provides cathodic protection for the exposed surfaces of the piping for a long period of time, which is why galvanizing is the standard method of corrosion mitigation in steel. Therefore, galvanized piping is not subject to accelerated corrosion of the base metal due to coating holidays.

Delamination, blistering, flaking, or peeling of galvanized coating only occurs when a certain set of metallurgical phenomena is present. Delamination, blistering, flaking, or peeling in the transformer deluge system and foam extinguishing system galvanized piping has not been identified in Limerick OE (10-year review). The Fire Water System (B.2.1.18) aging management program, as amended by Exelon's response to LR-ISG-2012-02 dated March 12, 2014, includes flow testing of the transformer deluge systems and foam extinguishing system. The flow tests for the main and auxiliary transformers are performed every two years, and for the other transformers the flow tests are performed every three years. The foam extinguishing system is flow tested annually. These flow tests verify the absence of blockage which could occur due to coating failure.

Item number (8): Coating inspection is not required for the galvanized portions of the normal waste, oily waste, sanitary waste and storm drain piping in the Plant Drainage System since, as stated above, galvanized piping is not subject to accelerated corrosion of the base metal due to coating holidays. Delamination, blistering, flaking, or peeling in the galvanized normal waste, oily waste, and storm drain piping that could result in flow blockage has not been identified in Limerick OE (10-year review). However, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26) aging management program, as amended by Exelon's response to LR-ISG-2012-02, will be used to manage the aging effect of loss of material, which is an indication of the loss of coating, in galvanized Plant Drainage System piping exposed to a waste water environment.

Item number (9): The Fire Water System Backup Water Storage Tank internal coating is not addressed in the response to this RAI. Internal inspection requirements for the Fire Water System Backup Water Storage Tank are addressed in Exelon's response to LR-ISG-2012-02.

For item numbers (1), (2), (3), (4), (5), and (6), coating inspections are required to manage loss of coating integrity. The inspections will be performed as follows:

1. Inspection Methods

   Visual inspections are performed as part of the appropriate aging management programs for the applicable systems, as identified in response item 3 below. Visual inspection may be supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined necessary by the inspector to accurately assess coating condition.

2. Parameters Monitored

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

3. Inspection Timing and Frequency

   Inspection activities for coatings will be performed in the Period of Extended Operation (PEO) as part of the Open-Cycle Cooling Water System (B.2.1.12) aging management program (Reactor Enclosure Cooling Water (RECW) Heat Exchangers, MCR Chiller Condensers, Circulating Water System piping), the Fire Water System (B.2.1.18) aging management program (Cement lined portions of the Fire Protection System piping), the Fuel Oil Chemistry (B.2.1.20) aging management program (Emergency Diesel Generator Diesel Oil Storage Tanks), and the Lubricating Oil Analysis (B.2.1.27) aging management program (RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir) as discussed below.

   - Cleaning and internal inspection of the service water side of the four RECW Heat Exchangers is currently being performed and will continue to be performed in the PEO as part of the Open-Cycle Cooling Water System (B.2.1.12) aging management program. The service water side of the heat exchangers is internally coated with an epoxy coating which is currently inspected at a two year frequency. These coatings

are nonsafety-related. Failure of the coatings could result in unanticipated or accelerated corrosion of the base metal only. The service water side of the RECW Heat Exchangers is scoped for license renewal in the Nonsafety-Related Service Water (NSSW) System. This system is in scope for 10 CFR 54.4(a)(2) spatial interaction only. Therefore, coating failure will not prevent an in-scope component from satisfactorily accomplishing any of its functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3) as a result of degraded performance (e.g., reduction in flow, drop in pressure, reduction in heat transfer) due to flow blockage.

The coatings in the service water side of the RECW Heat Exchangers were last inspected in April 2012 (1A), October 2013 (1B), January 2013 (2A), and April 2013 (2B). The 1A, 1B and 2A had coating degradation that required repair or replacement. The coating of 2B was found to be in good condition.

Since coating degradation that required repair or replacement has been identified in the service water side of the RECW Heat Exchangers, visual inspections at a two year frequency are appropriate. Baseline inspections will occur in the 10-year period prior to the period of extended operation. The frequency of subsequent inspections will be established based on the baseline inspections.

- Cleaning and internal visual inspection of the service water side of the two MCR Chiller Condensers is currently being performed and will continue to be performed in the PEO as part of the Open-Cycle Cooling Water System (B.2.1.12) aging management program. These inspections assess the internal condition of the service water side of the chiller condenser as part of GL 89-13 program activities. The epoxy coatings on chiller condenser components are part of the inspections. These coatings are safety-related. The service water side of the MCR Chiller Condensers is scoped for license renewal in the Safety-Related Service Water (SRSW) System. This system is in scope for 10 CFR 54.4(a)(1). Therefore, failure of these coatings could result in unanticipated or accelerated corrosion of the base metal or could prevent a downstream in-scope component from satisfactorily performing its intended function.

  The chiller condensers are currently internally inspected for GL 89-13 at a one year frequency and were last inspected in March 2013 (0A) and February 2013 (0B). In addition, visual inspections that specifically assess the condition of the safety-related coating on the service water side of the MCR Chiller Condensers are also performed every six years. These coating inspections were last performed in March 2010 (0A) and May 2010 (0B).

  Both the 2010 and 2013 inspections of the 0A chiller found the coating to be in good condition. The 2010 inspection of the 0B chiller found the overall condition of the coating to be good but identified that the baffle plate had several areas along its edges where there was a loss of coating. This condition was evaluated, and it was determined that the chiller condenser could be returned to service without immediate repair of the coating. The coating was subsequently repaired during the next annual chiller inspection in March 2011. The 2013 inspection of the 0B chiller found the coating to be in good condition. A minor coating flaw identified in the 2012 inspection was re-inspected and no additional degradation was identified.

Since coating degradation in the service water side of the MCR Chiller Condensers that required repair or replacement has been identified, and coating deficiencies determined to not require immediate remediation were identified, visual inspections at a one year frequency are appropriate. The periodic 6 year safety-related coating condition assessment inspections are currently not an implementing activity for the Open-Cycle Cooling Water System (B.2.1.12) aging management program. These inspections will be added as new implementing activities for the Open-Cycle Cooling Water System (B.2.1.12) aging management program and will continue through the PEO. Baseline inspections will occur in the 10-year period prior to the period of extended operation. The frequency of subsequent inspections will be established based on the baseline inspections.

- Internal inspection of the coal tar coated Circulating Water System piping is currently being performed and will continue to be performed in the PEO as part of Open-Cycle Cooling Water System (B.2.1.12) aging management program. These coatings are nonsafety-related. Failure of these coatings could result in unanticipated or accelerated corrosion of the base metal or could prevent a downstream in-scope component from satisfactorily performing its intended function. The piping is currently internally inspected at a ten year frequency and was last inspected in March 2008 (Unit 1) and March 2005 (Unit 2). The inspections included "cold" piping from the cooling tower to the condenser and "hot" piping from the condenser to the cooling tower which incorporates all portions of coated in scope circulating water piping. During these inspections, the Unit 1 coating was found to be satisfactory with no defects identified. The Unit 2 coating was found to be satisfactory with only minor defects identified, which did not appear to have changed since the last inspection. Because these coating defects did not change from the previous inspection, the defects did not require coating repair prior to returning the system to service.

  In April 2013, "hot" circulating water piping from the Unit 2 condenser to the cooling towers was internally inspected in support of plant maintenance activities. The scope of the inspection included one of the four 78 inch branch lines from the condenser waterboxes and its attached 96 inch main circulating water pipe. During these inspections, coating degradation was identified. Limited coating repairs were performed prior to returning the circulating water piping to service.

  The coated portions of the in scope circulating water piping will receive a baseline visual inspection within 10 years prior to the period of extended operation. The scope of the inspection will be 73 one-foot axial sections. The frequency of subsequent inspections will be based on the baseline inspection results.

- The internal surfaces of the buried cement lined fire main header is currently being managed and will continue to be managed in the PEO by the Fire Water System (B.2.1.18) aging management program. This piping is normally inaccessible. Failure of the cement lining could result in unanticipated or accelerated corrosion of the base metal or could prevent a downstream in-scope component from satisfactorily performing its intended function. Currently the internal surfaces are not visually inspected. Instead, the cement lined fire main header is flow tested every 18 months and will be flow tested at least once every year in the PEO as part of the Buried and

Underground Piping and Tanks (B.2.1.29) aging management program. The flow test procedure measures system hydraulic resistance as a means of evaluating the internal piping conditions and verifying that degradation has not occurred. Additionally, the fire hydrants connected to the fire main header are flow tested annually. Evidence of flow blockage during these tests would provide an indication of main header cement liner degradation. Finally, a system flush is performed at least once per 12 months as part of demonstrating system operability. These activities will continue through the PEO.

A review of plant specific OE for the past 10 years did not identify any failures in the cement lining of the fire water piping. Three opportunistic inspections performed during replacement of post indicating valves (PIVs) did not identify degradation of the cement lining. Within 10 years prior to the PEO, five additional inspections will be performed during PIV replacement activities. In addition, in October of 2012 Exelon Power Labs, LLC performed an opportunistic analysis of a portion of cement lined pipe and identified that the inner cement lining was in good condition with no cracks identified. LGS will continue to do opportunistic inspections of the cement lined pipe in the PEO as part of the Fire Water System (B.2.1.18) aging management program when normally inaccessible surfaces are made accessible due to required plant activities.

- Cleaning and internal inspection of the Emergency Diesel Generator Diesel Oil Storage Tanks is currently being performed and will continue to be performed in the PEO as part of the LGS Fuel Oil Chemistry (B.2.1.20) aging management program. The program includes periodic internal inspection of each fuel oil tank at least once during the 10-year period prior to the period of extended operation and at least once every 10-years during the period of extended operation. Currently, these tanks are drained, cleaned, and inspected on a 10-year frequency.

  The sump area and bottom vertical foot of the Emergency Diesel Generator Diesel Oil Storage Tanks are coated with an epoxy coating. These coatings are safety-related. Failure of these coatings could result in unanticipated or accelerated corrosion of the base metal or could prevent a downstream in-scope component from satisfactorily performing its intended function. The internal coating of all eight of the Emergency Diesel Generator Diesel Oil Storage Tanks was last visually inspected in 2008. One tank was identified as having two areas of chipped coating in the bottom section of the sump which exposed the carbon steel substrate. A technical evaluation was performed by the site coating coordinator to evaluate the as-found coating defects. The coating damage was evaluated to be mechanical damage and not age related degradation. Only a small amount of surface rust staining was visible on the exposed carbon steel. Significant rusting would not be expected since current fuel oil chemistry practices limit the amount of water, sediment, and particulate contamination collected in the tank. These fuel oil chemistry activities will continue in the PEO as part of the Fuel Oil Chemistry (B.2.1.20) aging management program. The edges of the damaged coating were scraped to sound coating, re-inspected, and found to have satisfactory adhesion. Several smaller chips were also identified on the sump side walls. Due to the nature of the defects, coating repair was not required. The technical evaluation concluded that the tank could be returned to service without recoating these areas where the coating had been chipped and that

the inspection frequency of 10 years was still appropriate. Additionally, minor coating deficiencies were identified in three other tanks. These conditions were within acceptance criteria. However, baseline inspections will occur in the 10-year period prior to the period of extended operation. The frequency of subsequent inspections will be established based on the baseline inspections.

- The RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir were originally coated internally with Rust-Ban paint. Failure of the coatings in the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir could result in unanticipated or accelerated corrosion of the base metal or could prevent a downstream in-scope component from satisfactorily performing its intended function. The pedestals and reservoir are managed by the Lubricating Oil Analysis (B.2.1.27) aging management program. The Lubricating Oil Analysis (B.2.1.27) aging management program includes oil sampling and oil change activities that are capable of detecting coating degradation. The oil sampling associated with the Lubricating Oil Analysis (B.2.1.27) aging management program includes testing for particulate in the oil, every 91 days, which would indicate degradation of the internal coating of the bearing pedestals and reservoir or of the base metal. Current periodic maintenance activities also identify and address coating deficiencies. HPCI and RCIC turbine oil is drained each refueling outage during the turbine inspection. The HPCI oil reservoir is cleaned and inspected each refueling outage. The HPCI and RCIC bearing pedestals are also drained and opened each outage for bearing and drive accessory inspections. These inspections include a visual assessment of coating condition. Any internal coating that is found degraded during these periodic inspections is removed. The uncoated substrate is not recoated.

  The RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir coating will receive a baseline visual inspection within 10 years prior to the period of extended operation. The frequency of subsequent inspections will be established based on the baseline inspections.

4. Extent of Inspections

   Coated surfaces that are accessible upon component disassembly or entry are visually inspected during each inspection interval.

5. Training and Qualification

   Examiners currently performing coating assessment inspections of the safety-related coating in the Emergency Diesel Generator Diesel Oil Storage Tanks (10-year frequency) and MCR Chiller Condensers (6 year frequency) are qualified to at least one of the following:

   a. ASTM D-4537-91 (endorsed in RG 1.54) and ANSI N45.2.6-1978, to a minimum of level II

   b. VT-3 to a minimum of Level II including documented orientation in performing coating surveillance

In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. This level of qualification will continue through the PEO for these inspections.

Additionally, examiners currently performing GL 89-13 program inspections of the MCR Chiller Condensers (one-year frequency) are qualified to engineer certification guides which include knowledge of EPRI TR-1019157, Guideline on Nuclear Safety-Related Coatings, Rev. 2 and a knowledge objective requirement to describe the inspection of coatings in heat exchangers. This level of qualification will continue through the PEO for these inspections.

Examiners currently performing service water side inspections of the RECW Heat Exchangers (two-year frequency) are qualified to engineer certification guides which include knowledge of EPRI TR-1019157, Guideline on Nuclear Safety-Related Coatings, Rev. 2 and a knowledge objective requirement to describe the inspection of coatings in heat exchangers. This level of qualification will continue through the PEO for these inspections. This is acceptable since, as discussed in item 3 above, the service water side of the RECW Heat Exchangers is scoped for license renewal in the Nonsafety-Related Service Water (NSSW) System. This system is in scope for 10 CFR 54.4(a)(2) spatial interaction only. Therefore, coating failure will not prevent an in-scope component from satisfactorily accomplishing any of its functions identified under 10 CFR 54.4(a)(1), (a)(2), or (a)(3) as a result of degraded performance (e.g., reduction in flow, drop in pressure, reduction in heat transfer) due to flow blockage.

Inspections performed on the RCIC turbine bearing pedestals, HPCI turbine bearing pedestals and oil reservoir, and nonsafety-related Circulating Water System coatings are not currently performed by qualified coating inspectors. As described in item 3 above, baseline inspections will be performed on these components within 10 years prior to PEO using qualified coating inspection personnel. Subsequent periodic inspections will be based on the baseline inspection results. These subsequent inspections will be performed by qualified coating personnel.

6. Trending

The as-found condition of the coating is documented in inspection reports or in completion remarks in the inspection work order. The results of previous inspections are used to determine changes in the condition of the coating over time. Trending of coating degradation is utilized to establish appropriate inspection frequencies for components with internal coatings. These frequencies are chosen to identify coating degradation before degradation of the base metal occurs such that intended functions of the coated component, or, the intended function of downstream components, are maintained.

7. Acceptance Criteria

Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. Coating defects are entered into the corrective action program for evaluation. As necessary, visual inspection may be supplemented by additional testing

such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the inspector to accurately assess coating condition.

8. Corrective Actions

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

   Limerick currently has a Site Coating Coordinator who provides oversight of safety-related coating activities. Deficiencies in safety-related coatings are documented and reported to the Site Coating Coordinator for evaluation. The Site Coating Coordinator performs many of the activities performed by the Nuclear Coatings Specialist position described in ASTM D 7108. However, the current Site Coating Coordinator position is not qualified in accordance with ASTM D 7108. As discussed in LRA Section A.2.1.37 for the Protective Coating Monitoring and Maintenance Program, the position of Nuclear Coatings Specialist will be created at the site prior to the PEO. ASTM D 7108 will be used for establishing the qualifications for this position.

9. Program Augmentation

   Aging management and inspection activities for coatings are currently being performed and will continue to be performed in the PEO as part of the Open-Cycle Cooling Water System (B.2.1.12) aging management program (Reactor Enclosure Cooling Water (RECW) Heat Exchangers, MCR Chiller Condensers, Circulating Water System piping), the Fire Water System (B.2.1.18) aging management program (Cement lined portions of the Fire Protection System piping), the Fuel Oil Chemistry (B.2.1.20) aging management program (Emergency Diesel Generator Diesel Oil Storage Tanks), and the Lubricating Oil Analysis (B.2.1.27) aging management program (RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir).

   LRA Sections 3.2.2.1.3, 3.2.2.1.4, 3.3.2.1.8, 3.3.2.1.9, 3.3.2.1.12, 3.3.2.1.22, 3.4.2.1.1 and Tables 3.2.2-3, 3.2.2-4, 3.3.2-8, 3.3.2-9, 3.3.2-12, 3.3.2-22, and 3.4.2-1 are revised as shown in Enclosure B to identify systems and components with internal coatings. In addition, LRA Appendix A Sections A.2.1.12, A.2.1.18, A.2.1.20, A.2.1.27 and LRA Appendix B Sections B.2.1.12, B.2.1.18, B.2.1.20, and B.2.1.27 are revised as shown in Enclosure B to identify aging management activities that will be performed to manage loss of coating integrity for in scope components with internal coatings. LRA Table A.5, Commitments 12, 18, 20, and 27 are revised as shown in Enclosure C.

Enclosure B
Updates to affected LRA sections

Notes:

- 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 following LGS LRA sections are changed by this response:

Section 3.2.2.1.3
Section 3.2.2.1.4
Section 3.3.2.1.8
Section 3.3.2.1.9
Section 3.3.2.1.12
Section 3.3.2.1.22
Section 3.4.2.1.1

Table 3.2.2-3
Table 3.2.2-4
Table 3.3.2-8
Table 3.3.2-9
Table 3.3.2-12
Table 3.3.2-22
Table 3.4.2-1

Appendix A.2.1.12
Appendix A.2.1.18
Appendix A.2.1.20
Appendix A.2.1.27

Appendix B.2.1.12
Appendix B.2.1.18
Appendix B.2.1.20
Appendix B.2.1.27

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.2.2.1.3 is revised as follows:

3.2.2.1.3 High Pressure Coolant Injection System

Materials

The materials of construction for the High Pressure Coolant Injection System components are:

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

Aging Effects Requiring Management

The following aging effects associated with the High Pressure Coolant Injection System components require management:

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.2.2.1.4 is revised as follows:

3.2.2.1.4 Reactor Core Isolation Cooling System

Materials

The materials of construction for the Reactor Core Isolation Cooling System components are:

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

Aging Effects Requiring Management

The following aging effects associated with the Reactor Core Isolation Cooling System components require management:

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.3.2.1.8 is revised as follows:

3.3.2.1.8 Emergency Diesel Generator System

Materials

The materials of construction for the Emergency Diesel Generator System components are:

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

Aging Effects Requiring Management

The following aging effects associated with the Emergency Diesel Generator System components require management:

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.3.2.1.9 is revised as follows:

3.3.2.1.9 Fire Protection System

Materials

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

- Aluminum
- Cafecote
- Carbon Steel
- ***Carbon Steel (with internal coatings)***
- 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
- Polymer
- Soil (Asphalt covered)
- Stainless Steel
- Thermolag

Aging Effects Requiring Management

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

- Concrete cracking and spalling
- Cracking
- Cracking and spalling
- Cumulative Fatigue Damage
- Hardening and Loss of Strength
- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.3.2.1.12 is revised as follows:

3.3.2.1.12 Nonsafety-Related Service Water System

Materials

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

- Carbon Steel
- ***Carbon Steel (with internal coatings)***
- Carbon and Low Alloy Steel Bolting
- Cast Austenitic Stainless Steel (CASS)
- Copper
- Copper Alloy
- Copper Alloy with 15% Zinc or More
- Ductile Cast Iron
- Glass
- Gray Cast Iron
- Stainless Steel
- Stainless Steel Bolting

Aging Effects Requiring Management

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

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.3.2.1.22 is revised as follows:

3.3.2.1.22 Safety Related Service Water System

Materials

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

- Carbon Steel
- ***Carbon Steel (with internal coatings)***
- Carbon and Low Alloy Steel Bolting
- Carbon or Low Alloy Steel with Stainless Steel Cladding
- Copper Alloy with less than 15% Zinc
- Elastomer
- Glass
- Stainless Steel
- Stainless Steel Bolting

Aging Effects Requiring Management

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

- Cracking
- Hardening and Loss of Strength
- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload
- Reduction of Heat Transfer

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section 3.4.2.1.1 is revised as follows:

3.4.2.1.1 Circulating Water System

Materials

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

- Carbon Steel
- ***Carbon Steel (with internal coatings)***
- Carbon and Low Alloy Steel Bolting
- Elastomer
- Glass
- Polymer
- Stainless Steel
- Stainless Steel Bolting

Aging Effects Requiring Management

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

- Cracking
- Hardening and Loss of Strength
- ***Loss of Coating Integrity***
- Loss of Material
- Loss of Preload

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.2.2-3, pages 3.2-48 and 3.2-51, is revised as follows:

Table 3.2.2-3 High Pressure Coolant Injection System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tank (Turbine Lube Oil Reservoirs)	Pressure Boundary	Gray Cast Iron ***(with internal coatings)***	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.27)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.22)	V.D2.EP-77	3.2.1-49	A
				Loss of Coating Integrity	***Lubricating Oil Analysis (B.2.1.27)***			***H, 5***

Plant Specific Notes:

5. The aging effects for gray cast iron with an internal coating in a lubricating oil environment include loss of coating integrity. The Lubricating Oil Analysis (B.2.1.27) program is used to manage the identified aging effect applicable to gray cast iron with an internal coating in a lubricating oil environment.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.2.2-4, pages 3.2-58 and 3.2-61, is revised as follows:

Table 3.2.2-4 Reactor Core Isolation Cooling System (Continued)

Component Type	Intended Function	Material	Environment	Aging Effect Requiring Management	Aging Management Programs	NUREG-1801 Item	Table 1 Item	Notes
Tanks (Turbine Lube Oil Reservoirs)	Pressure Boundary	Gray Cast Iron ***(with internal coatings)***	Air - Indoor, Uncontrolled (External)	Loss of Material	External Surfaces Monitoring of Mechanical Components (B.2.1.25)	V.E.E-44	3.2.1-40	A
			Lubricating Oil (Internal)	Loss of Material	Lubricating Oil Analysis (B.2.1.27)	V.D2.EP-77	3.2.1-49	A
					One-Time Inspection (B.2.1.22)	V.D2.EP-77	3.2.1-49	A
				Loss of Coating Integrity	***Lubricating Oil Analysis (B.2.1.27)***			***H, 5***

Plant Specific Notes:

5. The aging effects for gray cast iron with an internal coating in a lubricating oil environment include loss of coating integrity. The Lubricating Oil Analysis (B.2.1.27) program is used to manage the identified aging effect applicable to gray cast iron with an internal coating in a lubricating oil environment.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.3.2-8, pages 3.3-136 and 3.3-141, is revised as follows:

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
Tanks (Fuel Oil Storage Tanks)	Pressure Boundary	Carbon Steel	Air - Outdoor (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.H1.A-95	3.3.1-67	E, 1
			Air/Gas - Wetted (Internal)	Loss of Material	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	VII.H2.A-23	3.3.1-89	C
			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
			Soil (External)	Loss of Material	Buried and Underground Piping and Tanks (B.2.1.29)	VII.H1.AP-198	3.3.1-106	C
		Carbon Steel (with internal coatings)	***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***
				Loss of Coating Integrity	***Fuel Oil Chemistry (B.2.1.20)***			***H, 6***
			Soil (External)	***Loss of Material***	***Buried and Underground Piping and Tanks (B.2.1.29)***	***VII.H1.AP-198***	***3.3.1-106***	***C***

Plant Specific Notes:

6. The aging effects for carbon steel with an internal coating in a fuel oil environment include loss of coating integrity. The Fuel Oil Chemistry (B.2.1.20) program is used to manage the identified aging effect applicable to carbon steel with an internal coating in a fuel oil environment.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.3.2-9, pages 3.3-146, 3.3-150, and 3.3-154, 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	Pressure Boundary	Cement	Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.18)	VII.C1.AP-249	3.3.1-33	E, 5
				Loss of Coating Integrity	***Fire Water System (B.2.1.18)***			***H, 11***
		Copper Alloy with less than 15% Zinc	Air - Indoor, Uncontrolled (External)	None	None	VII.J.AP-144	3.3.1-114	A
			Fuel Oil (Internal)	Loss of Material	Fuel Oil Chemistry (B.2.1.20)	VII.G.AP-132	3.3.1-69	A
					One-Time Inspection (B.2.1.22)	VII.G.AP-132	3.3.1-69	A
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.18)	VII.G.AP-197	3.3.1-64	A
		Ductile 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
			Raw Water (Internal)	Loss of Material	Fire Water System (B.2.1.18)	VII.G.A-33	3.3.1-64	A

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
Tanks (10-T402 Backup Fire Water Storage Tank)	Pressure Boundary	Carbon Steel ***(with internal coating)***	Air - Outdoor (External)	Loss of Material	Aboveground Metallic Tanks (B.2.1.19)	VII.H1.A-95	3.3.1-67	A
			Air/Gas - Wetted (Internal)	Loss of Material	Aboveground Metallic Tanks (B.2.1.19)	VII.G.A-23	3.3.1-89	E, 10
			Raw Water (Internal)	Loss of Material	Aboveground Metallic Tanks (B.2.1.19)	VII.G.A-33	3.3.1-64	E, 10
				Loss of Coating Integrity	***Aboveground Metallic Tanks (B.2.1.19)***			***H, 12***
			Soil (External)	Loss of Material	Aboveground Metallic Tanks (B.2.1.19)	VIII.E.SP-115	3.4.1-30	A

Plant Specific Notes:

11. The aging effect for cement lined pipe in a raw water environment includes loss of coating integrity. The Fire Water System (B.2.1.18) program is used to manage the identified aging effect applicable to cement lined pipe in a raw water environment.

12. The aging effects for carbon steel with an internal coating in a raw water environment include loss of coating integrity. The Aboveground Metallic Tanks (B.2.1.19) program is used to manage the identified aging effect applicable to carbon steel with an internal coating in a raw water environment.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.3.2-12, pages 3.3-168 and 3.3-171, is revised as follows:

Table 3.3.2-12 Nonsafety-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
Heat Exchanger Components (Recombiner Aftercondenser~~,~~ ***and*** Fuel Pool Heat Exchanger~~, and Reactor Enclosure Cooling Water Heat Exchanger~~ tube side components)	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	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-183	3.3.1-38	A
Heat Exchanger Components (Reactor Enclosure Cooling Water Heat Exchanger tube side components)	***Leakage Boundary***	***Carbon Steel (with internal coatings)***	***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***	***Open-Cycle Cooling Water System (B.2.1.12)***	***VII.C1.AP-183***	***3.3.1-38***	***A***
				Loss of Coating Integrity	***Open-Cycle Cooling Water System (B.2.1.12)***			***H, 1***

Plant Specific Notes:

~~None.~~

1. ***The aging effects for carbon steel with an internal coating in a raw water environment include loss of coating integrity. The Open-Cycle Cooling Water System (B.2.1.12) program is used to manage the identified aging effect applicable to carbon steel with an internal coating in a raw water environment.***

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.3.2-22, pages 3.3-228 and 3.3-232, is revised as follows:

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
Heat Exchanger Components (MCR Chiller Condenser)	Heat Transfer	Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Reduction of Heat Transfer	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.A-72	3.3.1-42	A
	Pressure Boundary	Carbon Steel ***(with internal coatings)***	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	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-183	3.3.1-38	A
				Loss of Coating Integrity	***Open-Cycle Cooling Water System (B.2.1.12)***			***H, 4***
		Copper Alloy with less than 15% Zinc	Raw Water (Internal)	Loss of Material	Open-Cycle Cooling Water System (B.2.1.12)	VII.C1.AP-179	3.3.1-38	A

Plant Specific Notes:

4. The aging effects for carbon steel with an internal coating in a raw water environment include loss of coating integrity. The Open-Cycle Cooling Water System (B.2.1.12) program is used to manage the identified aging effect applicable to carbon steel with an internal coating in a raw water environment.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Table 3.4.2-1, pages 3.4-29, 3.4-30, and 3.4-32, is revised as follows:

Table 3.4.2-1 **Circulating Water System**

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)	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
		Carbon Steel (with internal coatings)	***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***
				Loss of Coating Integrity	***Open-Cycle Cooling Water System (B.2.1.12)***			***H, 4***

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	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
		Carbon Steel (with internal coatings)	***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***
				Loss of Coating Integrity	***Open-Cycle Cooling Water System (B.2.1.12)***			***H, 4***
			Soil (External)	***Loss of Material***	***Buried and Underground Piping and Tanks (B.2.1.29)***	***VIII.E.SP-145***	***3.4.1-47***	***A***

Plant Specific Notes:

4. The aging effects for carbon steel with an internal coating in a raw water environment include loss of coating integrity. The Open-Cycle Cooling Water System (B.2.1.12) program is used to manage the identified aging effect applicable to carbon steel with an internal coating in a raw water environment.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section A.2.1.12, Open-Cycle Cooling Water System is revised as follows:

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.

Periodic volumetric inspections will be performed in the non-buried portions of the Safety Related Service Water System to provide a sufficient understanding of the buried service water piping conditions throughout the period of extended operation. The inspection locations are selected to ensure that conditions are similar (e. g. flow, temperature) to those in the buried portions of the Safety Related Service Water System piping.

The OCCWS aging management program also manages the loss of coating integrity in a raw water environment. Internal coatings in the service water side of the Main Control Room Chiller Condensers and Reactor Enclosure Cooling Water Heat Exchangers, and in circulating water system piping are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Individuals performing the inspection of coatings whose failure could result in accelerated degradation of material or degradation of downstream components due to flow blockage will be qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. The inspection of coatings whose failure could result in accelerated degradation of material but not degradation of downstream components due to flow blockage will be performed

using plant specific procedures by inspectors qualified through plant specific programs. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair prior to the component being returned to service.

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 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.

5. Perform periodic inspections for loss of material in the Safety Related Service Water System at a minimum of ten locations every two years.

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section A.2.1.18, Fire Water System is revised as follows:

A.2.1.18 Fire Water System

The Fire Water System aging management program is an existing program that provides for system pressure monitoring, fire system header flushing and flow testing, pump performance testing, hydrant flushing, and visual inspection activities. System flow tests measure hydraulic resistance and compare results with previous testing as a means of evaluating the internal piping conditions. The program manages loss of material due to corrosion, including MIC, fouling, ~~and~~ flow blockage because of fouling***, and loss of coating integrity***. Major component types include piping, piping components and piping elements, tanks, pump casings, and valve bodies. Monitoring system piping flow characteristics ensures that signs of loss of material will be detected in a timely manner. ***Monitoring system piping flow characteristics and opportunistic internal inspections of the cement lined fire main ensure that signs of loss of coating integrity will be detected in a timely manner. Within 10 years prior to the PEO, five inspections of the cement lined fire main will be performed.*** Pump performance tests, hydrant flushing and system inspections are based on guidance from the applicable National Fire Protection Association (NFPA) standards. The fire water system is normally maintained at required operating pressure and is monitored such that loss of system pressure is immediately detected and corrective actions initiated. Fire system main header flow tests, sprinkler system inspections, visual yard hydrant inspections, hydrostatic tests, gasket inspections, volumetric inspections, and fire hydrant flow tests and pump capacity tests are performed periodically to assure that aging effects are managed such that the system intended functions are maintained.

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

1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 “Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems” (2011 Edition), Section 5.3.1.1.1. This testing will be performed prior to the 50-year in-service date and every 10 years thereafter.

2. Inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter.

3. Inspect and clean line strainers for deluge systems after each actuation. Strainers for deluge systems subject to periodic full flow testing will be inspected and cleaned on a frequency consistent with the deluge system test frequency.

4. Inspect and clean the foam system water supply strainer after each system actuation and no less than once per refueling outage interval.

5. Perform external visual inspection of deluge spray nozzles and piping for the HVAC charcoal filters for signs of leakage, corrosion, physical damage, and correct orientation once per refueling outage interval.

6. Perform flow tests for the hydraulically most remote hose stations every five years with a portion of the tests performed in each year of the five year interval.

7. Perform a main drain test annually for the fire water piping in each of the following locations: Unit 1 Reactor Enclosure, Unit 2 Reactor Enclosure, Unit 1 Turbine Enclosure, Unit 2 Turbine Enclosure, Control Enclosure, and Radwaste Enclosure. Flow blockage or abnormal discharge identified during flow testing or any change in pressure during the test greater than ten percent at a specific location is entered into the corrective action program for evaluation.

8. Perform charcoal filter deluge valve exercise testing and air flow testing at least once per refueling outage interval and perform air flow testing for the deluge systems for the hydrogen seal oil units and lube oil reservoirs every three years.

9. Perform the following for Fire Water System sprinkler systems:

   - Perform visual internal inspections for corrosion and obstructions to flow on at least five wet pipe sprinkler systems every five years.

   - Collect and evaluate solids discharged from wet pipe sprinkler system flow testing. Flow testing will be performed on an interval no greater than 18 months for each wet pipe system.

   - Perform visual internal inspections for corrosion and obstructions to flow for dry pipe preaction sprinkler systems of surfaces made accessible when preaction and water deluge valves are serviced on an interval no greater than a refueling outage interval.

   - Perform visual internal inspections for corrosion and obstructions to flow for deluge sprinkler systems of surfaces made accessible when deluge valves are serviced on at least ten deluge systems on an interval no greater than three years.

   - Perform a visual internal inspection for corrosion and obstructions to flow for any wet pipe, dry pipe preaction, or deluge sprinkler system after any non-test system actuation prior to return to service.

   - Perform an obstruction evaluation for conditions that indicate degraded flow.

   - Perform volumetric inspections for pipe wall thickness if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal wall thickness.

- Sprinkler systems that are normally dry but may be wetted as the result of testing or actuations will have augmented tests and inspections on piping segments that cannot be drained or piping segments that allow water to collect. These augmented inspections will be performed in each five year interval beginning five years prior to the period of extended operation and consist of either a flow test or flush sufficient to detect potential flow blockage or a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. In addition, in each five year interval of the period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections.

10. Perform wall thickness measurements using UT or other suitable techniques at five selected locations every year to identify loss of material in the carbon steel backup fire water piping. These inspections will be performed until the piping degradation no longer meets the criteria for recurring internal corrosion.

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section A.2.1.20, Fuel Oil Chemistry is revised as follows:

A.2.1.20 Fuel Oil Chemistry

The Fuel Oil Chemistry aging management program is an existing mitigation and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The Fuel Oil Chemistry program manages loss of material in piping, piping elements, piping components and tanks in a fuel oil environment. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Specifications, Technical Requirements Manual, and ASTM guidelines. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and internally inspected. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations.

The Fuel Oil Chemistry program also manages the loss of coating integrity in a fuel oil environment. Fuel oil tank internal coatings are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Individuals performing the inspections will be qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair prior to the component being returned to service.

The Fuel Oil Chemistry aging management program will be enhanced to:

1. Periodically drain water from the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank.

2. Perform internal inspections of the Fire Pump Engine Diesel Oil Day Tank, the Fire Pump Diesel Engine Fuel Tank, and the Diesel Generator Day Tanks at least once during the 10-year period prior to the period of extended operation, and, at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained, cleaned and the internal surfaces either volumetrically or visually inspected. If evidence of degradation is observed during visual inspections, the diesel fuel tanks will require follow-up volumetric inspection.

3. Perform periodic analysis for total particulate concentration and microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank.

4. Perform periodic analysis for water and sediment and microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks.

5. Perform periodic analysis for water and sediment content, total particulate concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks.

6. Perform analysis of new fuel oil for water and sediment content, total particulate concentration and the levels of microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank.

7. Perform analysis of new fuel oil for total particulate concentration and the levels of microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks.

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

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, LRA Section A.2.1.27, Lubricating Oil Analysis is revised as follows:

A.2.1.27 Lubricating Oil Analysis

The Lubricating Oil Analysis aging management program is an existing program that provides oil condition monitoring activities to manage the loss of material and the reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. Sampling, analysis, and condition monitoring activities identify specific wear products and contamination and determine the physical properties of lubricating oil within operating machinery. These activities are used to verify that the wear product and contamination levels and the physical properties of lubricating oil are maintained within acceptable limits to ensure that intended functions are maintained.

The Lubricating Oil Analysis program also manages the loss of coating integrity in a lube oil environment. The RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir internal coatings are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Individuals performing the inspections will be qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair prior to the component being returned to service.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, the Program Description section of LRA Section B.2.1.12, Open-Cycle Cooling Water System is revised as follows:

B.2.1.12 Open-Cycle Cooling Water System

Program Description

The Open-Cycle Cooling Water System (OCCWS) aging management program is an existing program that includes mitigative, preventive, performance monitoring, and condition monitoring activities to manage heat exchangers, piping, piping elements, and piping components in safety-related and nonsafety-related raw water systems that are exposed to a raw water or air/gas wetted environment for loss of material, reduction of heat transfer, and hardening and loss of strength of elastomers. The activities for this program are consistent with the LGS commitments to the requirements of GL 89-13 and provide for management of aging effects in raw water cooling systems through tests, inspections and component cleaning. System and component testing, visual inspections, non-destructive examination (i. e. Radiographic Testing, Ultrasonic Testing, and Eddy Current Testing), and biocide and chemical treatment 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 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.

The guidelines of GL 89-13 are utilized for the surveillance and control of biofouling for the OCCWS. Procedures provide instructions and controls for chemical and biocide injection. Periodic inspections are performed for the presence of mollusks and biocide treatments are applied as necessary.

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. Periodic inspection and cleaning is performed on the heat exchangers without a heat transfer intended function.

Routine inspections and maintenance ensure that corrosion, erosion, sediment deposition and biofouling cannot degrade the performance of safety-related systems serviced by OCCWS. No credit is taken for protective coatings on safety-related components in the OCCWS. ~~Protective coatings on the Circulating Water System piping are periodically inspected and repaired.~~ The In-service Inspection (ISI) program provides for periodic leakage detection of buried piping and components as well as inspection of aboveground piping and components.

Examination of polymeric materials in systems serviced by OCCWS will be consistent with examinations described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26) program.

System walkdowns are performed periodically to assess the material condition of OCCWS piping and components. Compliance with the licensing basis is ensured by review of system design basis documents as well as periodic performance of focused area self-assessments and safety system functional inspections.

Periodic volumetric inspections will be performed in the non-buried portions of the Safety Related Service Water System to provide a sufficient understanding of the buried service water piping conditions throughout the period of extended operation. The inspection locations are selected to ensure that conditions are similar (e. g. flow, temperature) to those in the buried portions of the Safety Related Service Water System piping.

The OCCWS aging management program also manages the loss of coating integrity in a raw water environment. Internal coatings are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Baseline inspections will occur in the 10-year period prior to the period of extended operation and will include accessible internal surfaces of the service water side of the Main Control Room Chiller Condensers and Reactor Enclosure Cooling Water Heat Exchangers, and the entire inside surface of 73 one-foot axial length circumferential segments of coated circulating water system piping. Individuals performing the inspection of coatings whose failure could result in accelerated degradation of material or degradation of downstream components due to flow blockage will be qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. The inspection of coatings whose failure could result in accelerated degradation of material but not degradation of downstream components due to flow blockage will be performed using plant specific procedures by inspectors qualified through plant specific programs. The as-found condition of the coating is documented in inspection reports or in completion remarks in the inspection work order. The results of previous inspections are used to determine changes in the condition of the coating over time. Trending of coating degradation is utilized to establish appropriate inspection frequencies. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair prior to the component being returned to service.

Enhancements to the program, including internal inspections of buried pipe and periodic inspection of the Nonsafety-Related Service Water System piping will be implemented prior to entering the period of extended operation.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, the Program Description section of LRA Section B.2.1.18, Fire Water System is revised as follows:

B.2.1.18 Fire Water System

Program Description

The Fire Water System program is an existing program that manages identified aging effects for the water-based fire protection system and associated components, through the use of periodic inspections, monitoring, and performance testing. The program provides for preventive measures and inspection activities to detect loss of material prior to loss of intended functions. System functional tests, flow tests, flushes and inspections are performed in accordance with the applicable guidance from National Fire Protection Association (NFPA) codes and standards. The program applies to water-based fire protection systems that consist of sprinklers, nozzles, valves, hydrants, hose stations, standpipes, water storage tanks, and aboveground and underground piping and components. The environments managed by the program for fire components are air-outdoor and raw water. Fire system main header flow tests, sprinkler system inspections, visual yard hydrant inspections, fire hydrant hose inspections, hydrostatic tests, gasket inspections, volumetric inspections, and fire hydrant flow tests and pump capacity tests are performed periodically assure that aging effects are managed such that the system intended functions are maintained. ***Monitoring system piping flow characteristics and opportunistic internal inspections of the cement lined fire main ensure that signs of loss of coating integrity will be detected in a timely manner***. ***Within 10 years prior to the PEO, five inspections of the cement lined fire main will be performed.*** 50-year sprinkler head testing will be conducted using the guidance provided in NFPA 25. Performance of the initial 50-year tests will be determined based on the date of the sprinkler system installation. Subsequent inspections will be performed every 10 years after the initial 50-year testing.

Selected portions of the fire protection system piping located aboveground and exposed to water will be inspected by non-intrusive volumetric examinations, to ensure that aging effects are managed and that wall thickness is within acceptable limits. The initial wall thickness inspections will be performed before the end of the current operating term and thereafter at a frequency of at least once every 10 years during the period of extended operation. These inspections will be capable of evaluating (1) wall thickness to ensure against catastrophic failure and (2) the inner diameter of the piping as it applies to the flow requirements of the fire protection system.

The backup fire water storage tank internal and external surfaces are inspected and volumetric examinations of the tank bottom are performed as described in the Aboveground Metallic Tanks (B.2.1.19) program. External surfaces of buried fire main piping are evaluated as described in the Buried and Underground Piping and Tanks (B.2.1.29) program.

The fire water system is maintained at the required normal operating pressure and monitored such that a loss of system pressure is immediately detected and corrective actions initiated. The program ensures that testing and inspection activities have been

performed and the results have been documented and reviewed by the Fire Protection system manager for analysis and trending.

The system flow testing, visual inspections and volumetric inspections assure that aging effects are managed such that the system intended functions are maintained.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, the Program Description section of LRA Section B.2.1.20, Fuel Oil Chemistry is revised as follows:

B.2.1.20 Fuel Oil Chemistry

Program Description

The Fuel Oil Chemistry aging management program is an existing mitigation and condition monitoring program that includes activities which provide assurance that contaminants are maintained at acceptable levels in fuel oil for systems and components within the scope of license renewal. The Fuel Oil Chemistry program manages loss of material in piping, piping elements, piping components and tanks in a fuel oil environment. The fuel oil tanks within the scope of license renewal are maintained by monitoring and controlling fuel oil contaminants in accordance with the Technical Specifications, Technical Requirements Manual, and ASTM guidelines. Fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and internally inspected. These activities effectively manage the effects of aging by maintaining potentially harmful contaminants at low concentrations.

The Fuel Oil Chemistry program also manages the loss of coating integrity in a fuel oil environment. Fuel oil tank internal coatings are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Baseline inspections will occur in the 10-year period prior to the period of extended operation and will include accessible internal surfaces of the fuel oil tanks. Individuals performing the inspections will be qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. The as-found condition of the coating is documented in inspection reports or in completion remarks in the inspection work order. The results of previous inspections are used to determine changes in the condition of the coating over time. Trending of coating degradation is utilized to establish appropriate inspection frequencies. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair prior to the component being returned to service.

As a result of the response to RAI 3.0.3-1 provided in Enclosure A of this letter, the Program Description section of LRA Section B.2.1.27, Lube Oil Analysis is revised as follows:

B.2.1.27 Lube Oil Analysis

Program Description

The Lubricating Oil Analysis aging management program is an existing program that provides oil condition monitoring activities to manage loss of material and reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. Sampling, analysis, and condition monitoring activities identify specific wear products and contamination and determine the physical properties of lubricating oil within operating machinery. These activities are used to verify that the wear product and contamination levels and the physical properties of the lubricating oil are maintained within acceptable limits to ensure that intended functions are maintained.

The program directs the condition monitoring activities (sampling, analyses, and trending), thereby preserving an environment that is not conducive to loss of material or reduction of heat transfer. The lubricating oil testing (sampling and analysis) and condition monitoring activities identify detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. The contaminant levels (e.g., water and particulates) are trended in the program's database, and recommendations are made when adverse trends are observed, which could include in-leakage and corrosion product buildup.

The Lubricating Oil Analysis program is a condition monitoring program, the monitoring methods are effective in detecting the applicable aging effects and the frequency of monitoring is adequate to prevent significant degradation

The Lube Oil Analysis program also manages the loss of coating integrity in a lube oil environment. The RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir internal coatings are visually inspected to ensure that loss of coating integrity is detected prior to (1) loss of component intended function, including loss of function due to accelerated degradation caused by localized coating failures, and (2) degradation of downstream component performance due to flow blockage. Baseline inspections will occur in the 10-year period prior to the period of extended operation and will include accessible internal surfaces of the bearing pedestals and reservoir. Individuals performing the inspections will be qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities. The as-found condition of the coating is documented in inspection reports or in completion remarks in the inspection work order. The results of previous inspections are used to determine changes in the condition of the coating over time. Trending of coating degradation is utilized to establish appropriate

inspection frequencies. Inspections are performed for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. When acceptance criteria are not met, visual inspection is supplemented by additional testing such as DFT (Dry Film Thickness), adhesion, continuity, or other inspection technique as determined by the qualified inspector to accurately assess coating condition. Evaluations are performed for inspection results that do not satisfy established acceptance criteria and the conditions are entered into the LGS 10 CFR 50 Appendix B corrective action program. The corrective action program ensures that conditions adverse to quality are promptly corrected. Corrective actions may include coating repair prior to the component being returned to service.

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 RAI:

RAI 3.0.3-1

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 3.0.3-1 provided in Enclosure A of this letter, LRA, Appendix A, Table A.5, Commitments 12, 18, 20, and 27 are revised as follows:

A.5 License Renewal Commitment List

	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 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. 5. Perform periodic inspections for loss of material in the Safety Related Service Water System at a minimum of ten locations every two years. ***The Open-Cycle Cooling Water System aging management program also manages the loss of coating integrity in the service water side of the Main Control Room Chiller Condensers and Reactor Enclosure Cooling Water Heat Exchangers, and, in circulating water system piping.*** • ***As described below, baseline inspections will occur in the 10-year period prior to the period of extended***	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 LGS letter dated 6/22/12 RAI B.2.1.12-3 ***LGS Letter dated 3/14/14 RAI 3.0.3-1***

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		operation. The frequency of subsequent inspections will be established based on the baseline inspections. • ***The inspection of the Main Control Room Chiller Condensers will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities.*** • ***The inspection of the Reactor Enclosure Cooling Water Heat Exchangers will be performed by inspectors qualified through plant specific programs.*** • ***The inspection of 73 one-foot axial length circumferential segments of coated circulating water system piping will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities.***		

A.5 License Renewal Commitment List

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
18	Fire Water System	Fire Water System is an existing program that will be enhanced to: 1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2011 Edition), Section 5.3.1.1.1. This testing will be performed prior to the 50-year in-service date and every 10 years thereafter. 2. Inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed prior to the period of extended operation and will be performed every 10 years thereafter. 3. Inspect and clean line strainers for deluge systems after each actuation. Strainers for deluge systems subject to full flow testing will be inspected and cleaned on a frequency consistent with the deluge test frequency. 4. Inspect and clean the foam system water supply strainer after each system actuation and no less than once per refueling interval. 5. Perform external visual inspection of deluge piping and nozzles for the HVAC charcoal filters for signs of leakage, corrosion, physical damage, and correct orientation once per refueling interval. 6. Perform flow tests for the hydraulically most remote hose stations once every five years, scheduling the testing so that	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.18 LR-ISG-2012-02 review 03/11/2014 ***LGS Letter dated 3/14/14 RAI 3.0.3-1***

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		some of the tests are performed in each year of the five year interval. 7. Perform a main drain test annually for the fire water piping in each of the following locations: Unit 1 Reactor Enclosure, Unit 2 Reactor Enclosure, Unit 1 Turbine Enclosure, Unit 2 Turbine Enclosure, Control Enclosure, and Radwaste Enclosure. Flow blockage or abnormal discharge identified during flow testing or any change in pressure during the test greater than ten percent at a specific location is entered into the corrective action program for evaluation. 8. Perform charcoal filter deluge valve exercise testing and air flow testing at least once per refueling interval and perform air flow testing for the deluge systems for the hydrogen seal oil units and lube oil reservoirs every two years. 9. Perform the following for Fire Water System sprinkler and deluge systems: • Perform visual internal inspections, consistent with NFPA 25, for corrosion and obstructions to flow on at least five wet pipe sprinkler systems every five years. • Collect and evaluate solids discharged from wet pipe sprinkler system flow testing. Flow testing through the inspector's test valve will be performed on an interval no greater than 18 months for each wet pipe system. • Perform visual internal inspections for corrosion and obstructions to flow for dry pipe preaction sprinkler systems of surfaces made accessible when preaction and water deluge valves are serviced on an interval no greater than a refueling interval. • Perform visual internal inspections for corrosion and		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		obstructions to flow for deluge systems of surfaces made accessible when deluge valves are services on at least ten deluge systems on an interval no greater than three years. • Perform a visual internal inspection for corrosion and obstructions to flow for any wet pipe, dry pipe preaction, or deluge system after any system actuation prior to return to service. • Perform an obstruction evaluation for conditions that indicate degraded flow. • Perform follow-up volumetric inspections for pipe wall thickness if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal wall thickness. • Sprinkler and deluge systems that are normally dry but may be wetted as the result of testing or actuations will have augmented tests and inspections on piping segments that cannot be drained or piping segments that allow water to collect. These augmented inspections will be performed in each five year interval beginning five years prior to the period of extended operation and consist of either a flow test or flush sufficient to detect potential flow blockage or a visual inspection of 100 percent of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. In addition, in each five year interval of the period of extended operation, 20 percent of the length of piping segments that cannot be drained or piping segments that allow water to collect is subject to volumetric wall thickness inspections. 10. Perform wall thickness measurements using UT or other suitable techniques at five selected locations every year to identify loss of material in the carbon steel backup fire water piping. These inspections will be performed until the piping		

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		degradation no longer meets the criteria for recurring internal corrosion. ***The Fire Water System aging management program also manages the loss of coating integrity in the buried cement lined fire main header.*** • ***System flow testing activities measure system hydraulic resistance as a means of evaluating the internal piping condition.*** • ***Opportunistic internal inspections evaluate the condition of the cement lined fire main header.*** • ***Within 10 years prior to the PEO, five internal visual inspections of the cement lining in the fire main header will be performed.***		

A.5 License Renewal Commitment List

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
20	Fuel Oil Chemistry	Fuel Oil Chemistry is an existing program that will be enhanced to: 1. Periodically drain water from the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank. 2. Perform internal inspections of the Fire Pump Engine Diesel Oil Day Tank, the Fire Pump Diesel Engine Fuel Tank, and the Diesel Generator Day Tanks, at least once during the 10-year period prior to the period of extended operation and at least once every 10 years during the period of extended operation. Each diesel fuel tank will be drained, cleaned and the internal surfaces either volumetrically or visually inspected. If evidence of degradation is observed during visual inspections, the diesel fuel tanks will require follow-up volumetric inspection. 3. Perform periodic analysis for total particulate concentration and microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank. 4. Perform periodic analysis for water and sediment and microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks. 5. Perform periodic analysis for water and sediment content, total particulate concentration, and the levels of microbiological organisms for the Diesel Generator Day Tanks.	Program to be enhanced prior to the period of extended operation. Inspection schedule identified in commitment.	Section A.2.1.20 ***LGS Letter dated 3/14/14 RAI 3.0.3-1***

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
		6. Perform analysis of new fuel oil for water and sediment content, total particulate concentration and the levels of microbiological organisms for the Fire Pump Engine Diesel Oil Day Tank and the Fire Pump Diesel Engine Fuel Tank. 7. Perform analysis of new fuel oil for total particulate concentration and the levels of microbiological organisms for the Diesel Generator Diesel Oil Storage Tanks. ***The Fuel Oil Chemistry aging management program also manages the loss of coating integrity in the eight main fuel oil storage tanks.*** • ***As described below, baseline inspections will occur in the 10-year period prior to the period of extended operation. The frequency of subsequent inspections will be established based on the baseline inspections.*** • ***The inspection of the eight main fuel oil storage tanks will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities.***		

A.5 License Renewal Commitment List

	PROGRAM OR TOPIC	COMMITMENT	IMPLEMENTATION SCHEDULE	SOURCE
27	Lubricating Oil Analysis	Existing program is credited. ***The Lube Oil Analysis aging management program also manages the loss of coating integrity in the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir.*** • ***As described below, baseline inspections will occur in the 10-year period prior to the period of extended operation. The frequency of subsequent inspections will be established based on the baseline inspections.*** • ***The inspection of the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir will be performed by inspectors qualified to ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II, or, VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. In the event the initial inspection is not performed by an ANSI N45.2.6 inspector and the coating condition is considered suspect or requires coating repair then a qualified N45.2.6 inspector will perform a detailed inspection and oversee/inspect coatings recoats, touch-ups, or repair activities.***	Ongoing	Section A.2.1.27 ***LGS Letter dated 3/14/14 RAI 3.0.3-1***