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

August 12, 2014

Mr. Michael P. Gallagher
Vice President, License Renewal Projects
Exelon Generation Company, LLC
200 Exelon Way
P.O. Box 500
Kennett Square, PA 19348

SUBJECT: SUPPLEMENT 1 SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL OF LIMERICK GENERATING STATION, UNITS 1 AND 2 (TAC NOS. ME6555 AND ME6556)

Dear Mr. Gallagher:

By letter dated June 22, 2011, Exelon submitted its License Renewal Application (LRA) to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the Limerick Generating Station (LGS) operating licenses for an additional 20 years. The NRC staff (the staff) issued a safety evaluation report (SER) related to the license renewal of Limerick Generating Station, Units 1 and 2, dated January 10, 2013 (Agencywide Documents Access and Management System Accession No. ML13015A191), which summarizes the results of its review of the LRA for compliance with the requirements of Title 10, Part 54, of the Code of Federal Regulations (10 CFR Part 54), “Requirements for Renewal of Operating Licenses for Nuclear Power Plants.”

The enclosed Supplement 1 SER documents the staff’s review of supplemental information provided by the applicant since the issuance of the SER. This information includes annual updates required by 10 CFR 54.21(b) and updated information and commitments in response to the recent industry operating experience.

If you have any questions regarding this matter, please contact the license renewal project manager, Richard Plasse at 301-415-1427 or by e-mail at richard.plasse@nrc.gov.

Sincerely,

***/RA/***

John W. Lubinski, Director
Division of License Renewal
Office of Nuclear Reactor Regulation

Docket Nos. 50-352 and 50-353

Enclosure:
Supplement 1 Safety Evaluation Report

cc w/encl: Listserv

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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).

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# Safety Evaluation Report

Related to the License Renewal of Limerick Generating Station, Units 1 and 2

Supplement 1

Docket Nos. 50-352 and 50-353

Exelon Generation Company, LLC

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# ABSTRACT

This document is a supplemental safety evaluation report (SSER) for the license renewal application (LRA) for Limerick Generating Station (LGS), Units 1 and 2, as submitted by Exelon Generation Company, LLC (Exelon or the applicant). By letter dated June 22, 2011, Exelon submitted its LRA to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the LGS operating licenses for an additional 20 years. The NRC staff (the staff) issued a safety evaluation report (SER) related to the license renewal of Limerick Generating Station, Units 1 and 2, dated January 10, 2013, (Agencywide Documents Access and Management System Accession No. ML13015A191), which summarizes the results of its review of the LRA for compliance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations*, (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This SSER documents the staff's review of supplemental information provided by the applicant since the issuance of the SER. This information includes annual updates required by 10 CFR 54.21(b) and updated information and commitments in response to the recent industry operating experience.

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# ABBREVIATIONS

| | |
|---|---|
| ACRS | Advisory Committee on Reactor Safeguards |
| ADAMS | Agencywide Documents Access and Management System |
| AERM | aging effect requiring management |
| AMP | aging management program |
| AMR | aging management review |
| ANSI | American National Standards Institute |
| ASME | American Society of Mechanical Engineers |
| ASTM | American Society for Testing and Materials |
| CAP | corrective action program |
| CFR | *Code of Federal Regulations* |
| CLB | current licensing basis |
| CLSM | controlled low strength material |
| CUI | corrosion under insulation |
| EDG | emergency diesel generator |
| EPRI | Electric Power Research Institute |
| Exelon | Exelon Generation Company, LLC |
| GALL | Generic Aging Lessons Learned |
| GL | generic letter |
| HDPE | high-density polyethylene |
| HPCI | high-pressure coolant injection |
| LGS | Limerick Generating Station |
| LRA | license renewal application |
| LR-ISG | license renewal interim staff guidance |

| | |
|---|---|
| MCR | main control room |
| mV | millivolt(s) |
| NACE | National Association of Corrosion Engineers |
| NFPA | National Fire Protection Association |
| NRC | U.S. Nuclear Regulatory Commission |
| OE | operating experience |
| ohm-cm | ohm-centimeter(s) |
| PIV | post indicating valves |
| ppm | part(s) per million |
| psid | pound(s) per square inch differential |
| RAI | request for additional information |
| RCIC | reactor core isolation cooling |
| RECW | reactor enclosure cooling water |
| RG | regulatory guide |
| SCC | stress-corrosion cracking |
| SER | safety evaluation report |
| SRP-LR | "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, Rev.2" |
| SSC | system, structure, and component |
| SSER | supplemental safety evaluation report |
| SW | service water |
| UFSAR | updated final safety analysis report |
| UT | ultrasonic testing |
| VT-3 | visual examination |

# SECTION 1

# INTRODUCTION AND GENERAL DISCUSSION

## 1.1 Introduction

This document is a supplemental safety evaluation report (SSER) for the license renewal application (LRA) for Limerick Generating Station (LGS), Units 1 and 2, as submitted by Exelon Generation Company, LLC (Exelon or the applicant). By letter dated June 22, 2011, Exelon submitted its LRA to the U.S. Nuclear Regulatory Commission (NRC) for renewal of the LGS operating licenses for an additional 20 years. The NRC staff (the staff) issued a safety evaluation report (SER) related to the license renewal of LGS, Units 1 and 2, dated January 10, 2013 (Agencywide Documents Access and Management System (ADAMS) Accession No. ML13015A191), which summarizes the results of its review of the LRA for compliance with the requirements of Title 10, Part 54, of the *Code of Federal Regulations* (10 CFR Part 54), "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

This SSER documents the staff's review of additional information provided by the applicant since the staff's issuance of the SER in January 2013. This information includes annual updates required by 10 CFR 54.21(b) and updated information and commitments in response to the recent industry operating experience. This SSER supplements portions of SER Sections 1, 3, Appendix A, and Appendix B.

## 1.4 Interim Staff Guidance

License renewal is a living program. The staff, industry, and other interested stakeholders gain experience and develop lessons learned with each renewed license. The lessons learned address the staff's performance goals of maintaining safety, improving effectiveness and efficiency, reducing regulatory burden, and increasing public confidence. License renewal interim staff guidance (LR-ISG) is documented for use by the staff, industry, and other interested stakeholders until incorporated into such license renewal guidance documents as the NUREG–1800 "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 2, December 2010 (SRP-LR) and the NUREG–1801, "Generic Aging Lessons Learned Report," Revision 2, December 2010 (GALL Report).

Table 1.4-1 shows the current set of LR-ISGs addressed in this SSER, as well as the SSER sections in which the staff addresses them. This SSER also discusses operating experience concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks.

**Table 1.4-1  Current License Renewal Interim Staff Guidance**

| ISG Issue (Approved ISG Number) | Purpose | SER Section |
|---|---|---|
| "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2, Aging Management Program (AMP) XI.M41, Buried and Underground Piping and Tanks" (LR-ISG-2011-03) | This LR-ISG provides changes to GALL Report AMP XI.M41 as an acceptable approach for managing the effects of aging of buried and underground piping and tanks. | SSER Section 3.0.3.2.12 |
| "Wall Thinning Due to Erosion Mechanisms" (LR-ISG-2012-01) | This LR-ISG provides an alternate approach to manage the effects of aging for wall thinning due to various erosion mechanisms for piping and components through AMP XI.M17, "Flow-Accelerated Corrosion." | SSER Section 3.0.3.1.8 |
| "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion under Insulation" (LR-ISG-2012-02) | This LR-ISG revises the guidance related to aging management activities associated with AMPs XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," XI.M27, "Fire Water System," XI.M29, "Aboveground Metallic Tanks," XI.M41, "Buried and Underground Piping and Tanks," Recurring Internal Corrosion, and Corrosion Under Insulation (CUI). | SSER Section 3.0.3.3 |

# SECTION 2

# STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

The staff does not have any changes or updates to this section of the safety evaluation report.

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# SECTION 3

# AGING MANAGEMENT REVIEW RESULTS

## 3.0 Applicant's Use of the Generic Aging Lessons Learned (GALL) Report

### 3.0.3 Aging Management Programs (AMPs)

#### *3.0.3.1 AMPs Consistent with the GALL Report*

3.0.3.1.8 Flow-Accelerated Corrosion

Summary of Changes. By letter dated September 25, 2013, the applicant stated that Exelon Generation Company, LLC (Exelon or the applicant), had performed a review of License Renewal Interim Staff Guidance (LR-ISG) -2012-01, "Wall Thinning Due to Erosion Mechanisms." The applicant also stated that Limerick Generating Station (LGS) recently implemented the guidance contained in this LR-ISG through its Flow-Accelerated Corrosion program. Based on its review, the applicant provided changes to license renewal application (LRA) Sections A.2.1.10 and B.2.1.10, to reflect the changes allowed by this LR-ISG, by including wall thinning mechanisms other than flow-accelerated corrosion to be managed by the Flow-Acceleration Corrosion program.

Staff Evaluation. The U.S. Nuclear Regulatory Commission (NRC) staff (the staff) notes that, as described in the safety evaluation report (SER), LGS's Flow-Accelerated Corrosion program is based on Electric Power Research Institute (EPRI) guidelines in NSAC-202L-R3, which provides guidance for susceptible-not-modeled piping. The staff also notes that, as described in LR-ISG-2012-01, piping or locations that are being monitored for wall thinning due to erosion mechanisms may be included with these susceptible-not-modeled lines and treated in a comparable fashion. The staff finds the applicant's proposal acceptable because it has implemented the guidance contained in LR-ISG-2012-01 for managing wall thinning due to erosion mechanisms.

Conclusion. The staff has concluded that no changes are required to the Flow-Accelerated Corrosion program. The program is adequate to manage the applicable aging effects.

#### *3.0.3.2 AMPs Consistent with the GALL Report with Exceptions or Enhancements*

3.0.3.2.12 Buried and Underground Piping and Tanks

Summary of Technical Information in the Application. LRA Section B.2.1.29 describes the existing Buried and Underground Piping and Tanks program as consistent, with enhancements, with GALL Report AMP XI.M41 "Buried and Underground Piping and Tanks." The LRA states that the AMP addresses the external surfaces of metallic buried and underground piping and tanks exposed to soil and the outdoor air environments to manage the effects of loss of material. The LRA also states that the AMP proposes to manage this aging effect through electrochemical verification of cathodic protection, nondestructive evaluation of pipe wall thickness of underground piping, visual inspections of the pipe during opportunistic excavations, external coatings, cathodic protection, and the quality of backfill used. This program augments other programs that manage the aging of internal surfaces of buried and underground piping and tanks. By letters dated June 17, 2013, and August 16, 2013, the applicant amended its Buried and Underground Piping and Tanks program to address LR-ISG-2011-03, "Changes to the Generic Aging Lessons Learned (GALL) Report Revision 2 Aging Management Program (AMP) XI.M41, 'Buried and Underground Piping and Tanks,'" which was issued in its final version on August 2, 2012.

Staff Evaluation. During the staff audit (Agencywide Documents Access and Management System (ADAMS) Accession No. ML12018A332), the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements 1-6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M41.

For the "preventive actions," "detection of aging effects," and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "preventive actions" program element in GALL Report AMP XI.M41 states that one acceptable way to mitigate loss of material for buried steel piping is to provide external coatings and cathodic protection. During its audit, the staff found that the Buried and Underground Piping and Tanks program states that the plant drainage system piping is neither coated nor cathodically protected, and the circulating water system piping is not coated. By letter dated January 17, 2012, the staff issued request for additional information (RAI) B.2.1.29-1 requesting the applicant to state the basis for how the aging of buried components in the plant drainage and circulating water systems will be adequately managed such that their intended functions will be maintained consistent with the current licensing basis (CLB) if cathodic protection and external coatings are not provided for the plant drainage system and external coatings are not provided for the circulating water system.

In its response, dated February 15, 2012, the applicant stated that, based on further review, the plant drainage system is coated with a somastic coating, the circulating water system is coated with coal tar epoxy, both coatings are recommended by National Association of Corrosion Engineers (NACE) SP0169-2007, and the plant drainage system piping is not cathodically protected because it is constructed from cast iron, a corrosion-resistant material.

The staff found the applicant's response acceptable because both piping systems are coated with coatings recommended by NACE SP0169-2007, which is referenced by GALL Report AMP XI.M41 as an acceptable standard for coatings. The staff does not agree with the applicant's stated basis for not installing cathodic protection (i.e., cast iron is a corrosion-resistant material). However, buried cast iron piping will not experience sufficient corrosion to result in a loss of piping function because cast iron components are designed with a thicker wall that allows much longer buried service. The staff's concern described in RAI B.2.1.29-1 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.M41 states that, if adverse indications are detected, one acceptable way to ensure that an adequate extent of condition review is conducted is to double the inspection sample size within the affected piping category, and if adverse indications are found in the expanded sample, the inspection sample size is again doubled, with the doubling of the inspection sample size continuing as necessary. During its audit, the staff found that the Buried and Underground Piping and Tanks program states that adverse conditions detected during inspections will be evaluated and the potential inspection expansion will be determined in accordance with the corrective action program (CAP). By letter dated January 17, 2012, the staff issued RAI B.2.1.29-2 requesting the applicant to state the basis for how the CAP inspection expansion size will be sufficient to detect degradation before it causes an in-scope component to not be capable of meeting its CLB function(s).

In its response dated February 15, 2012, the applicant stated that:

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

It was not clear to the staff whether the applicant's CAP would require doubling of the inspection sample size until a subsequent set of inspections detected no adverse conditions. The staff's concern described in RAI B.2.1.29-2 was not resolved.

By letter dated March 22, 2012, the staff issued followup RAI B.2.1.29-2.1 requesting the applicant to clarify what it means by "[t]his doubling of the inspection sample size continues as dictated by the corrective action program."

In its response, dated March 30, 2012, the applicant amended the last sentence of the enhancement to state, "[t]his doubling of the inspection sample size continues as necessary." The applicant revised LRA Sections A.2.1.29, B.2.1.29, and Enhancement No. 1, accordingly.

The staff found the applicant's response acceptable because the enhancement is consistent with the wording in AMP XI.M41. The staff's concern described in RAI B.2.1.29-2 and B.2.1.29-2.1 was resolved. However, the staff noted that LR-ISG-2011-03 revised the recommendations associated with inspection scope expansion when an adverse condition is detected. By letter dated June 17, 2013, the applicant revised Enhancement No. 1. The staff's evaluation of this change is documented in the below discussion associated with Enhancement No. 1.

The "acceptance criteria" program element in GALL Report AMP XI.M41 states that one acceptable way to ensure that the cathodic protection system is providing effective protection is to use the soil to pipe potential acceptance criteria found in NACE SP0169-2007. NACE SP0169-2007, Section 7.1.2.7, states that excessive levels of cathodic protection can cause external coating disbondment. During its audit, the staff found that the applicant's "Cathodic Protection Design Basis Document" stated that the cathodic protection system is required to maintain an energized voltage of not less than 850 millivolts (mV) negative potential with respect to a copper-copper sulfate reference electrode. By letter dated January 17, 2012, the staff issued RAI B.2.1.29-3 requesting the applicant to state an upper limit acceptance criterion for pipe to soil potential measurements, and to state the basis for using the stated value.

In its response, dated February 15, 2012, the applicant stated that the program has been amended to require that if during cathodic protection surveys a negative polarized potential exceeds −1100 mV relative to a copper-copper sulfate electrode, an issue report will be documented in the CAP. The applicant also stated that the −1100 mV value is consistent with Peabody's Control of Pipeline Corrosion, Second Edition 2001, NACE. In addition, the applicant revised LRA Sections A.2.1.29 and B.2.1.29 to reflect the additional acceptance criteria.

The staff found the applicant's response acceptable because the applicant has added an acceptance criterion that will ensure that excessive levels of cathodic protection will be addressed through the CAP, and the criterion, −1100 mV, is consistent with NACE SP0169-2007 and industry guidelines for cathodic protection. The staff's concern described in RAI B.2.1.29-3 was resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements associated with enhancements to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows. By letters dated June 17, 2013, and August 16, 2013, the applicant revised Enhancement Nos. 1, 3, and 5 through 8. The staff's evaluation of these revisions is shown below.

*Enhancement 1*. LRA Section B.2.1.29, as amended by the applicant's response to RAIs B.2.1.29-2 and B.2.1.29-2.1, and letter dated June 17, 2013, states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that, "[i]If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, an analysis is conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the extent of condition and extent of cause." The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M41 and finds it acceptable because when it is implemented it will be consistent with LR-ISG-2011-03 and it can ensure that the scope of inspections will be appropriate for the extent of conditions.

*Enhancement 2*. LRA Section B.2.1.29 states an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the applicant stated that it will coat the underground emergency diesel generator (EDG) system fuel oil piping before the period of extended operation in accordance with NACE standards. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M41 and finds it acceptable because when it is implemented it will be consistent with LR-ISG-2011-03 AMP XI.M41 Table 2b, Preventive Actions for Underground Piping and Tanks, which recommends that underground piping be coated in accordance with NACE standards.

*Enhancement 3*. As amended by letter dated June 17, 2013, LRA Section B.2.1.29 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements. In this enhancement, the applicant stated that it will perform direct visual inspections and volumetric inspections of the underground EDG system fuel oil piping and components during each 10-year period beginning 10 years before entry into the period of extended operation. Before the period of extended operation, all in-scope EDG system fuel oil piping and components located in underground vaults will undergo a 100-percent visual inspection. Volumetric inspections also will be performed. After entering the period of extended operation, 2 percent of the linear length of EDG system fuel oil piping and components within the scope of license renewal and located in underground vaults will undergo direct visual inspections and volumetric inspections every 10 years. Inspection locations after entering the period of extended operation will be selected based on susceptibility to degradation and consequences of failure. The applicant also stated that "[v]isual inspections will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course." The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented the requirements for visual inspection of external surfaces and qualification and training will be consistent with LR-ISG-2011-03 and will ensure that sufficient piping is inspected by an individual with the appropriate knowledge, skills, and abilities assesses coating conditions.

_Enhancement 4_. LRA Section B.2.1.29 states an enhancement to the "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that it will perform two sets of volumetric inspections of the safety-related service water (SW) system underground piping and components during each 10-year period beginning 10 years before entry into the period of extended operation. Each set of volumetric inspections will assess either the entire length of a run or a minimum of 10 feet of the linear length of the piping and components within the scope of license renewal. Inspection locations will be selected based on susceptibility to degradation and consequences of failure. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M41 and found it acceptable because when it is implemented it will be consistent with the visual inspection of external and volumetric inspection of internal surfaces recommendations of GALL Report AMP XI.M41.

_Enhancement 5_. As amended by letter dated June 17, 2013, LRA Section B.2.1.29 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course will conduct visual inspections of safety-related SW piping. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will ensure that potential coating degradation will be evaluated by an individual with appropriate knowledge, skills, and abilities to conduct the inspections.

_Enhancement 6_. As amended by letter dated June 17, 2013, LRA Section B.2.1.29 states an enhancement to the "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant stated that it will perform trending of cathodic protection testing results to identify changes in the effectiveness of the system and to ensure that the rectifiers required to protect piping within the scope of license renewal remain operational at least 85 percent of the time, and cathodic protection effectiveness will be maintained greater than 80 percent. The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will be consistent with LR-ISG-2011-03 and it can ensure that cathodic protection is available for the recommended amount of time and the system is providing an adequate level of protection.

*Enhancement 7*. LRA Section B.2.1.29, as amended by the response to RAI B.2.1.29-3, states an enhancement to the "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant stated that it will modify the yearly cathodic protection survey acceptance criterion to meet NACE standards. As stated above in the staff evaluation portion of this supplemental safety evaluation report (SSER), RAI B.2.1.29-3 was issued requesting that the applicant state an upper limit acceptance criterion for pipe to soil potential measurements, and state the basis for using the stated value. The staff evaluated the applicant's response to RAI B.2.1.29-3 and the amended Enhancement No. 7 against the corresponding program elements in GALL Report AMP XI.M41 and found it acceptable because, when it is implemented, it will be consistent with NACE SP0169-2007, which is referenced by GALL Report AMP XI.M41 as an acceptable standard for cathodic protection, and industry guidelines for cathodic protection.

By letter dated June 17, 2013, the applicant revised this enhancement to state that the acceptance criteria used to measure the effectiveness of the cathodic protection system for buried steel piping will be either a −850 mV polarized potential or a −100 mV polarization. The applicant stated that use of the −100 mV polarization criteria will be subject to being demonstrated effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured. The staff noted that the use of the −850 mV polarized potential criterion is consistent with LR-ISG-2011-03. However, LR-ISG-2011-03, Table 6a, "Cathodic Protection Acceptance Criteria," footnote 2, states that the −100 mV polarization criterion is limited to electrically isolated piping sections or areas of grounded piping where the effects of mixed potentials are shown to be minimal. ISO 15589-1, "Petroleum and natural gas industries – Cathodic protection of pipeline transportation systems," First Edition, Section 5.3.2.2 states that the use of the −100 mV polarization critetion should not be used in cases of pipelines connected to or consisting of mixed metals. While the staff recognizes that buried coupons, electrical resistance probes, or placement of reference cells can be used as effective means to detect corrosion rates or localized effectiveness of cathodic protection, the program does not state details such as what industry consensus documents will be used to install the devices. By letter dated August 1, 2013, the staff issued RAI B.2.1.29-4 Request (4) requesting that the applicant state which industry consensus documents will be used to install and use the corrosion rate monitoring devices or reference electrodes.

In its response dated August 16, 2031, the applicant revised LRA Sections A.2.1.29 and B.2.1.29, and Commitment No. 29 to remove the 100mV polarization criterion. The staff finds the applicant's response and enhancement acceptable because, in lieu of providing further information regarding how it would measure the effectiveness of using the 100 mV polarization criterion, it eliminated use of this criterion. The staff's concern described in RAI B.2.1.29-4 Request (4) is resolved.

*Enhancement 8*. By letter dated June 17, 2013, the applicant stated an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that "[w]henever pipe is excavated and damage to the coating is significant and the damage was caused by nonconforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation." The staff reviewed this enhancement against the corresponding program elements in LR-ISG-2011-03 and finds it acceptable because when it is implemented it will be consistent with LR-ISG-2011-03 and can ensure that an appropriate extent of condition is conducted when backfill conditions have led to coating damage.

Based on the revisions to the Buried and Underground Piping and Tanks program in the amendment letter dated June 17, 2013, the staff determined the need for additional information related to the “detection of aging effects” program element, which resulted in the issuance of RAIs as discussed below.

LRA Section B.2.1.29 states that direct inspections of buried piping are not required because of the preventive and mitigative measures included in the program. However, this was based in part because GALL Revision 2, AMP XI.M41, “Buried and Underground Piping and Tanks,” Table 4a, “Inspections of Buried Pipe,” did not state that buried nonsafety-related systems should be inspected. The circulating water and plant drainage systems are within the scope of license renewal and are nonsafety-related. While these systems are coated and buried in acceptable backfill, only the circulating water system is cathodically protected. LR-ISG-2011-03 Table 4a removed the distinction between code class safety-related, hazmat, and nonsafety-related piping.Table 4a states that all in-scope piping is subject to inspections. By letter dated August 1, 2013, the staff issued RAI B.2.1.29-4 Request (1) requesting that the applicant state (a) the number of inspections that will be conducted per unit on the in-scope buried plant drainage system piping; (b) whether the piping is buried in cementitious backfill; and (c) where not buried in cementitious backfill, if the pipe is coated.

In its reply dated August 16, 2013, the applicant stated:

- Both the safety-related service water system valve pit drains and main, safeguard, and auxiliary transformer dike drains are at atmospheric pressure and experience intermittent water flow.
- The in-scope plant drainage system piping is cast iron, which is a corrosion resistant material. As stated above, in the Staff Evaluation portion of this SSER section, the staff does not agree that cast iron piping is corrosion resistant; however, cast iron components are designed with a thicker wall that allows much longer buried service.
- The piping is coated and backfilled in a controlled low strength material (CLSM). Backfill may also be concrete or material in accordance with ASTM International (formerly known as American Society for Testing and Materials) D448-08, per plant specifications. Five excavations of the plant drainage system were performed since June of 2012, and all were found in their specified fill material. Resistivity measurements were taken of the backfill material around the pipe and were greater than 10,000 ohm-cm, which indicates low corrosivity. Eleven excavations of other plant system piping were performed since October of 2010 in various locations. The condition of the fillcrete was found to be in very good condition and was analyzed for pH and chlorides. The measured pH was 10.4 and chlorides were less than 40 [parts per million] ppm. The high pH is the result of hydroxyl ions and alkalis present in the pore solutions in the CLSM microstructure, not from dissolved salt, which is consistent with the low chloride levels. The results of the pH and chloride testing further support that the fillcrete material has low corrosivity and, therefore, provides additional corrosion protection of the piping. In addition, there is no adverse plant–specific operating experience concerning external corrosion of plant drainage system piping.

- If in-scope piping is excavated for any reason and coating is exposed, inspection of the coating will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.

The staff finds the applicant's proposal that plant drainage piping would only be inspected on an opportunistic basis acceptable. The staff has concluded that there is reasonable assurance that buried in-scope plant drainage piping will meet its CLB intended function(s) without a declared minimum number of inspections during the period of extended operation because:

- As evidenced by five excavations of the plant drainage system conducted since June of 2012, resistivity measurements of the backfill material around the pipe were greater than 10,000 ohm-cm. Based on U.S. Department of Transportation, Federal Highway Administration, Publication No. FHWA-NHI-00-044, "Corrosion/Degradation of Soil Reinforcements for Mechanically Stabilized Walls and Reinforced Soil Slopes," September 2000, soils with resistivity readings greater than 10,000 ohm-cm are considered noncorrosive.
- The piping is exposed to atmospheric pressure and, therefore, if there are holes in the piping, it is much less likely that local supporting soil would be washed away. In addition, it is very likely that water would continue to be conducted away from the SW system valve pits and transformer dike areas.
- The piping is coated which results in increased resistance to external corrosion.
- As evidenced by 11 excavations of other plant system piping conducted since October 2010, the condition of the fillcrete was found to be in very good condition, the measured pH was 10.4, and chlorides were less than 40 ppm.
- There is no adverse plant–specific operating experience concerning external corrosion of plant drainage system piping.

The staff noted that the applicant will use coating inspectors qualified consistent with the recommendations in LR-ISG-2011-03 which will ensure that an individual with the appropriate knowledge, skills, and abilities assesses coating conditions. The staff issued RAI B.2.1.29-4 Request (2) requesting that the applicant state whether inspection locations selected for buried in-scope plant drainage system piping would be based on risk. The staff notes that, with its acceptance of the response to RAI B.2.1.29-4 Request (1), Request (2) is not necessary because opportunistic inspections are not based on risk. The staff's concerns described in RAI B.2.1.29-4 Requests (1) and (2) are resolved.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.29-1, B.2.1.29-2, B.2.1.29-2.1, B.2.1.29-3, and B.2.1.29-4 Requests (1), (2), and (4), the staff finds that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of LR-ISG-2011-03. In addition, the staff reviewed the enhancements associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.29 summarizes operating experience (OE) related to the Buried and Underground Piping and Tanks program. The applicant stated that, in October 2010, an opportunistic inspection of fire protection and domestic water piping showed that there was no degradation of the coatings and wrappings on the piping and components. The applicant also stated that, in May 2008, inspections of all underground safety-related SW piping showed surface corrosion and some pitting. As a result, volumetric examinations were conducted, some repairs and replacements were completed, all piping was recoated, and future inspection activities were scheduled for inspecting all piping in all underground valve pits within the scope of license renewal on a 2-year frequency.

The staff reviewed OE information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific OE were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant OE information to determine whether the applicant had adequately evaluated and incorporated OE related to this program. During its review, the staff found no OE to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation. However, subsequent to the audit, LR-ISG-2011-03 was issued which states that, if cathodic protection is not provided, a 10-year search of plant-specific OE should be conducted to determine if adverse conditions have occurred in the impacted systems. Given that the plant drainage system is not cathodically protected, this 10-year search should be conducted. The search should include components that are not within the scope of license renewal if they are constructed from similar materials and buried in a similar environment. In addition, LR-ISG-2011-03 states that a basis should be provided for why cathodic protection is not provided during the period of extended operation. By letter dated August 1, 2013, the staff issued RAI B.2.1.29-4 Request (3) requesting that the applicant provide the results of a 10-year search of plant-specific OE related to the plant drainage system and state the basis for why cathodic protection will not be provided.

In its response dated August 16, 2013, the applicant stated that a review of plant-specific OE from January 1, 2000, through April 21, 2010, was performed to support the development of the aging management reviews (AMRs) prepared for the LRA. An additional review was performed from April 22, 2010, through August 1, 2013. These reviews identified 615 condition reports for both the in-scope and not-in-scope portions of the plant drainage system. No adverse conditions were identified for buried piping external surfaces.

The staff finds the applicant's response acceptable because its response supported the staff's need for plant-specific OE information in order to assess the acceptability of not providing cathodic protection for the buried in-scope plant drainage system piping. In addition, the staff noted that the applicant's supporting information for conducting only opportunistic inspections of this system (e.g., low soil corrosivity, intact coatings, acceptable backfill), further supports the case for not providing cathodic protection. The staff's concern described in RAI B.2.1.29-4 Request (3) is resolved.

Based on its audit and review of the applicant's response to RAI B.2.1.29-4 Request (3), the staff finds that the applicant has appropriately evaluated plant-specific and industry OE. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on systems, structures, and components (SSCs) within the scope of the program, and that implementation of the program has resulted in the applicant's taking corrective actions.

UFSAR Supplement. As amended by letters dated June 17, 2013, and August 16, 2013, LRA Section A.2.1.29 provides the updated final safety analysis report (UFSAR) supplement for the Buried and Underground Piping and Tanks program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the description in "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants, Rev. 2" (SRP-LR), Table 3.0-1, as revised by LR-ISG-2011-03.

The staff also noted that the UFSAR supplement contained a Commitment No. 29 to implement the enhancements, as described in the LRA, before the period of extended operation. The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the Buried and Underground Piping and Tanks program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of LR-ISG-2011-03. Also, the staff reviewed the enhancements and confirmed that their implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR supplement contained Commitment No. 29 to implement the enhancements before the period of extended operation. The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

### *3.0.3.3 Staff Evaluation of LRA Changes to Incorporate LR-ISG-2012-02, "Aging Management of Internal Surfaces, Fire Water Systems, Atmospheric Storage Tanks, and Corrosion Under Insulation"*

#### 3.0.3.3.1 Recurring Internal Corrosion

Summary of Changes. By letter dated March 12, 2014, the applicant provided its evaluation of LR-ISG-2012-02, Section A, "Recurring Internal Corrosion," and identified changes to the LRA. The applicant stated that it had identified recurring internal corrosion in several raw water systems, which are subject to ongoing inspections and piping replacements through the Open-Cycle Cooling Water System program. The applicant also stated that enhancements to the Open-Cycle Cooling Water System program had previously been made as documented in NRC SER Section 3.0.3.2.4, and these enhancements provide a combination of inspections, replacements, and material improvements to detect the presence of, and minimize the susceptibility to, recurring internal corrosion.

In addition, the applicant identified recurring internal corrosion in the portion of the fire water system associated with the backup diesel fire pump that is exposed to untreated raw water. Although LRA Sections A.2.1.18 and B.2.1.18 initially included an enhancement for the Fire Water System program to perform volumetric inspections of associated above-ground piping every 10 years, the applicant stated that it would further enhance this program to perform additional inspections to address recurring internal corrosion. As a result, the applicant provided a new enhancement (Enhancement No. 10) to perform annual wall-thickness measurements at five selected locations using ultrasonic or other suitable techniques until degradation of the backup fire water piping no longer meets the criteria for recurring internal corrosion.

Staff Evaluation. For components managed by the Open-Cycle Cooling Water System program, the identification of flaws can be addressed through the application of American Society of Mechanical Engineers (ASME) Code Case N-513-3, “Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping, Section XI, Division I.” The considerations for applying this approach include augmented volumetric examinations to assess the degradation of the affected system, which typically consists of an initial sample of the five most susceptible locations and additional samples whenever other flaws are detected. Based on this, the applicant’s previous enhancements are sufficient to address recurring internal corrosion in those systems managed by the Open-Cycle Cooling Water System program.

However, since ASME code cases do not apply to fire water system piping, for any flaws detected through the Fire Water System program, there did not appear to be comparable guidance for conducting augmented inspections of additional samples, if degradation is detected. Consequently, by letter dated April 24, 2014, the staff issued RAI 3.0.3.3.1-1 requesting the applicant to provide additional information regarding program activities whenever further degradation is identified during the annual inspections of the backup fire water system piping.

In its response dated May 21, 2014, the applicant revised Enhancement No. 10 for the Fire Water System program by providing information for additional inspections when wall-thickness measurements for recurring internal corrosion identify pipe degradation. The applicant proposed graduated inspection expansion criteria based on the extent of wall loss identified during these inspections. These criteria consisted of four, two, or no additional locations for wall loss greater than 50 percent, wall loss between 50 percent and 30 percent and the calculated remaining life is less than two years, or wall loss less than 30 percent, respectively. The applicant also revised LRA Sections A.2.1.18 and B.2.1.18, and Commitment No. 18, item 10, to reflect these criteria for additional inspection guidance. The staff finds the applicant’s response acceptable because the additional inspections performed by the applicant will, depending on the degree of wall loss identified, better quantify the extent of the recurring internal corrosion within the fire water system piping. The staff’s concern described in RAI 3.0.3.3.1-1 is resolved.

Conclusion. Based on the information provided, the staff concludes that the applicant appropriately identified and addressed recurring internal corrosion for the systems managed by the Open-Cycle Cooling Water System program and the Fire Water System program. By providing enhancements to both programs for augmented inspections, the staff concludes that the applicant met the criteria discussed in LR-ISG-2012-02, Section A, and has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.0.3.3.2 Representative Minimum Sample Size for Periodic Inspections in GALL Report AMP XI.M38

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review and changes to the LRA associated with the recommendations in LR-ISG-2012-02 Section B, “Representative Minimum Sample Size for Periodic Inspections in GALL Report AMP XI.M38, ‘Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.’”

Staff Evaluation. To ensure that the GALL Report AMP XI.M38 inspections include a representative sample, the staff revised the guidance through LR-ISG-2012-02 to specify the minimum sample size, frequency, and inspection location. The revision included a provision to inspect 20 percent of a representative population of in-scope components, with a maximum sample size of 25 components, in each 10-year period during the period of extended operation. In addition, the revision allows an inspection performed on a component in a more severe environment to be credited as an inspection performed in a less severe environment for the same material.

In its letter dated March 12, 2014, the applicant revised LRA Sections A.2.1.26, B.2.1.26, and Table A.5 to reflect the results of its review related to LR-ISG-2012-02, Section B. The applicant stated that it will revise its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to ensure that a representative sample of components is inspected in each 10-year period during the period of extended operation. The applicant also stated that a representative sample of 20 percent of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population will be inspected. Where practical, the applicant stated that the inspections will focus on the components most susceptible to aging due to time in service and severity of operating conditions. In addition to the minimum sampling, the applicant further stated that opportunistic inspections will continue in each 10-year period.

The applicant also stated that an inspection conducted on a component in a more severe environment may be credited as an inspection for a component in a less severe environment when the material and aging effects are the same. Alternatively, similar environments can be combined into a larger population provided that the inspections occur on components located in the most severe environment.

The staff finds the applicant's revisions to its Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the resulting sample size, inspection locations, and frequency are consistent with the recommendations in AMP XI.M38, as revised by LR-ISG-2012-02.

UFSAR Supplement Changes. The staff reviewed the changes to the UFSAR supplement description of the program as supplemented by letter dated March 12, 2014, and noted that the applicant's program description is consistent with the recommended description in SRP-LR Table 3.0-1, as revised by LR-ISG-2012-02. The staff also noted that the revisions described are consistent with the applicant's revisions to Commitment No. 26.

Conclusion. On the basis of its review of the proposed changes to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, as amended by letter dated March 12, 2014, the staff determined that those program elements for which the applicant claimed consistency with AMP XI.M38, as revised by LR-ISG-2012-02, are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

#### 3.0.3.3.3 Fire Water System

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review of the changes regarding managing the aging effects associated with fire water systems in LR-ISG-2012-02 Section C, “Flow Blockage of Water-Based Fire Protection System Piping, GALL Report AMP XI.M27, ‘Fire Water System,’” and associated appendices.

Staff Evaluation. The applicant addressed each of the 16 recommended inspections and tests listed in LR-ISG-2012-02 AMP XI.M27, Table 4a, “Fire Water System Inspection and Testing Recommendations.” The staff’s evaluation of the applicant’s review follows.

*Sprinkler Systems—Sprinkler Inspections*. The staff noted that National Fire Protection Association (NFPA) 25 Section 5.2.1.1 recommends annual visual inspections of sprinklers. The applicant stated that the fire water system includes 120 in-scope sprinkler systems, including wet pipe sprinkler systems, dry pipe preaction sprinkler systems, deluge systems, and deluge systems for charcoal filters. The Fire Water System program currently includes visual inspections of the majority of sprinkler systems for age-related degradation every 18 months consistent with the NRC-approved Fire Protection Program. Certain sprinkler systems that are not accessible during normal operation and are visually inspected at different intervals are as follows:

- Main and auxiliary transformer deluge systems are visually inspected during plant refueling outages but no less frequently than a refueling interval.
- Other transformer deluge systems are visually inspected on a 3-year frequency during the equipment outages.
- Visual inspection of nozzles for charcoal filter deluge systems is performed in conjunction with filter media replacement. Although no degradation has been identified during the visual inspections of the charcoal filter deluge systems, the program will be enhanced to perform the inspections once per refueling outage interval, coincident with filter media sampling and testing activities.

The applicant also stated that a review of plant-specific OE, including 669 sprinkler system procedure-driven inspections since 2000, has not revealed any age-related degradation that would warrant increasing the procedure driven sprinkler system visual inspections from every 18 months to annually.

The staff reviewed the applicant’s program including the exception to NFPA 25 Section 5.2.1.1 and finds it acceptable because: (a) consistent with the applicant’s statement regarding a lack of past inspection findings, the staff’s independent search of plant-specific OE during the audit did not reveal any evidence that age-related sprinkler degradation was occurring; (b) the inspection frequencies are consistent with the staff-approved Fire Protection Report for the applicant; and (c) there is a large enough number of sprinklers installed at the applicant’s site sufficient to establish an adverse performance trend, even with plant-specific inspections being completed less frequently than every 12 months.

*Sprinkler Systems—Sprinkler Testing*. The staff noted that NFPA 25 Section 5.3.1 recommends testing or replacement of sprinklers that have been in service for 50 years. The applicant stated that Enhancement No. 1 of the Fire Water System program already addresses sprinkler head replacement or testing in accordance with NFPA 25 Section 5.3.1.1.1. The enhancement states that sprinklers will be tested or replaced by their 50-year inservice date and every 10 years thereafter. The applicant revised LRA Sections A.2.1.18 and B.2.1.18 to update the referenced NFPA 25 edition for sprinkler testing from 2002 to 2011.

The staff finds the applicant's program acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

*Standpipe and Hose Systems—Flow Tests*. The staff noted that NFPA 25 Section 6.3.1 recommends that a flow test be conducted every 5 years at the hydraulically most remote hose connections of each zone of the standpipe system as well as main drain tests. The applicant stated that the Fire Water System program includes a flow test at the hydraulically most limiting location in each major structure every 5 years and hose station flow and shutoff valve tests for each hose station every 3 years. The staff's evaluation of main drain tests is documented below in the *Valves and System-Wide Testing* evaluation.

The staff finds the applicant's program acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

*Private Fire Service Mains—Underground and Exposed Piping Flow Tests*. The staff noted that NFPA 25 Section 7.3.1 recommends that underground and exposed piping flow tests be conducted every 5 years to determine the internal conditions of the piping. The applicant stated that it conducts the following tests: (a) an underground main flow test is performed every 18 months and, during the period of extended operation, at least once a year; (b) fire hydrant flow tests are performed annually; and (c) flow tests of the most hydraulically remote hose stations in each zone of the standpipe system are performed every 5 years.

The staff noted that, as stated in the *Standpipe and Hose System—Flow Tests* evaluation above, the applicant conducts hose station flow and shutoff valve tests for each hose station every 3 years. Also, the underground portions of the fire water system will be flow tested more frequently than recommended in NFPA 25. The staff reviewed the applicant's program, including this exception to NFPA 25 Section 7.3.1, and finds the program acceptable because the underground piping is tested more frequently than recommended by NFPA 25 Section 7.3.1 and the hose station tests provide insight into the internal condition of the associated portions of the exposed piping. This results in sufficient data for the applicant to determine if the internal condition of the underground and exposed piping is degrading.

*Private Fire Service Mains—Hydrants*. The staff noted that NFPA 25 Section 7.3.2 recommends annual hydrant testing. The applicant stated that the Fire Water System program includes annual testing of fire hydrants.

The staff finds the applicant's program acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27 and annual testing of fire hydrants provides insights into the internal conditions in the underground and exposed fire water system piping.

*Fire Pumps—Suction Screens*. The staff noted that NFPA 25 Section 8.3.3.7 recommends inspection and cleaning of fire pump suction screens after testing or system actuations. The applicant stated that the fire pumps do not have suction screens. The water sources for the fire water system are the cooling tower basin and the plant SW system. The cooling tower supply does not have screens. The supply from the plant SW system, which connects to the fire water system downstream of the fire pumps, includes a duplex basket strainer that is cleaned based on differential pressure indication. The inspection and cleaning of the stay-fill supply basket strainer does not provide indication of the condition of the fire water system. Therefore, it is not necessary to clean this strainer after system tests or actuations.

The staff noted that LR-ISG-0212-02 AMP XI.M27, Table 4a, footnote 1, states, "[t]his table specifies those inspections and tests that are related to age-managing applicable aging effects associated with loss of material and flow blockage for passive long-lived in-scope components in the fire water system." The staff finds the applicant's program acceptable because there are no strainers upstream of the fire pumps and the material that would collect on the plant SW system duplex basket strainer would not be indicative of conditions in the fire water system.

_Water Storage Tanks—Exterior Inspections_. The staff noted that NFPA 25 Section 9.2.5.5 recommends that the exterior insulated surfaces and support structure of fire water storage tanks be inspected on an annual basis. The applicant stated that it would maintain the backup water storage tank in the scope of its Aboveground Metallic Tanks program, which has exterior inspections on a refueling outage interval. By letter dated April 24, 2014, the staff issued RAI 3.0.3.3.3-1 requesting that the applicant state why inspection of the backup water storage tank external insulated surfaces on a biennial basis is sufficient to provide reasonable assurance that the CLB intended function(s) of the backup water storage tank will be met for the period of extended operation or revise the program to conduct annual inspections.

In its response dated May 21, 2014, the applicant stated that the Aboveground Metallic Tanks program will be enhanced to include an annual visual inspection of the external surfaces of the tank's insulation to detect potential evidence of deterioration of the spray-on polyurethane foam-type insulation or fiberglass fabric outer layer, or water intrusion. LRA Sections A.2.1.19 and B.2.1.19 and Commitment No. 19 state that rips, tears, and gaps in the insulation skin will be repaired and evidence of water intrusion beneath the insulation will be evaluated in accordance with the CAP.

Based on inspections of the tank during the audit, the staff noted that, if the outer insulation skin remains intact, there is a low likelihood for water to penetrate to the tank's external surface. The staff finds the applicant's response and program acceptable because conducting annual external visual inspections of the fire water storage tanks is consistent with LR-ISG-2012-02 AMP XI.M27 and the likelihood of loss of material on the external surfaces of the tank is very low as long as the outer insulation skin remains intact. The staff's concern described in RAI 3.0.3.3.3-1 is resolved. The staff's evaluation of managing corrosion under insulation (CUI) for the fire water storage tanks is documented in SSER Section 3.0.3.3.5.

_Water Storage Tanks—Interior Inspections_. The staff noted that NFPA 25 Sections 9.2.6 and 9.2.7 recommend that the internal surfaces of coated tanks be inspected every 5 years, and the inspections should include detection of pitting, corrosion, and local or general failure of the interior coating. The staff also noted that tanks on ring-type foundations with sand in the middle should be inspected for evidence of voids beneath the floor. The staff further noted that if loss of material or loss of coating integrity is detected, adhesion testing, dry film thickness measurements, ultrasonic testing (UT) thickness readings, wet-sponge testing, and vacuum box testing of the seams should be conducted. The staff noted that the applicant's review of Section D, "Revisions to the scope and inspection recommendations of GALL Report AMP XI.M29, 'Aboveground Metallic Tanks,'" of LR-ISG-2012-02 stated that the backup water storage tank is internally coated and sits on a compacted oil-treated sand bed.

The applicant stated that the Aboveground Metallic Tanks program includes internal surface visual inspections of the backup water storage tank conducted every 5 years and UT measurements of the tank bottom within 5 years prior to entering the period of extended operation and every 5 years thereafter. The applicant also stated that, if no tank bottom plate material loss is identified after the first two UT inspections, the volumetric inspections will be performed whenever the tank is drained during the period of extended operation. The program was further enhanced to:

- Perform visual inspections of the backup water storage tank wetted and nonwetted internal surfaces.
- Require that tank internal inspections be performed within 5 years before entering the period of extended operation and every 5 years thereafter.
- Require nondestructive examination of the tank bottom where visual inspection identifies pitting or general corrosion to below nominal wall thickness and to determine remaining wall thickness where bare metal has been exposed.
- Require that where pitting and general corrosion to below the nominal wall thickness occurs or any coating failure occurs in which bare metal is exposed, additional inspections and tests are performed, including adhesion testing of the coating in the vicinity of the coating failure and nondestructive examination to determine remaining wall thickness where bare metal has been exposed. In addition, adhesion testing will be performed in the vicinity of blisters even though bare metal may not be exposed.

The staff noted that not all of the testing and inspections recommended by NFPA 25 have been addressed by the applicant's review and enhancements. By letter dated April 24, 2014, the staff issued RAI 3.0.3.3.3-2 requesting that the applicant state the basis for reasonable assurance that the backup water storage tank will meet its CLB intended function(s) without conducting: (a) inspections for evidence of voids beneath the floor; and (b) dry film thickness measurements, wet-sponge testing, and vacuum box testing of the seams if loss of material or loss of coating integrity is detected.

In its response dated May 21, 2014, the applicant stated the Aboveground Metallic Tanks program will be enhanced to include a statement that, if the drained tank internal surface inspections identify pitting, corrosion, or failure of the coatings, the tests in NFPA 25 (2011 Edition) Section 9.2.7 will be performed. The applicant stated that, in some instances, vacuum box testing may not be practical and, in such cases, a magnetic particle examination will be conducted on weld seams. The applicant further stated that the tank bottom will be inspected for voids in accordance with NFPA 25 (2011 Edition) Section 9.2.6.5.

The staff noted that the purpose of vacuum box testing is to detect crack and through-wall pits in welds that would result in leaks. The staff finds the applicant's response and program acceptable because the tests and inspections of the internal surfaces of the tank will be consistent with LR-ISG-2012-02 AMP XI.M27 and because magnetic particle examinations are capable of detecting cracks and pits in welds. The staff's concern described in RAI 3.0.3.3.3-2 is resolved.

*Valves and System-Wide Testing—Main Drain Test*. The staff noted that NFPA 25, Section 13.2.5, recommends that a main drain test should be conducted annually at each fire water system riser. The applicant stated that the primary purpose of the test is to identify significant obstructions to flow such as a failed valve disc or mispositioned valve. The staff recognizes that NFPA 25 Section A.13.2.5 aligns with the applicant's statement; however, the staff included main drain testing in LR-ISG-2012-02 AMP XI.M27 because the testing can also detect partial flow blockage due to corrosion product buildup.

The applicant stated that it does not perform a main drain test at each riser. The applicant described the alternative testing as follows:

- Flow testing is performed at the hydraulically most limiting location in each major structure every 5 years. The tests are conducted at a total of 20 risers including those located in each of the reactor and turbine enclosures, as well as the control and radwaste enclosure. The riser drain valves are 1-inch size and have limited flow capability. The higher flow rates through the fire hose station will reveal flow obstructions more readily than if the drain valves were used. In addition, the use of the drain valves does not include the risers or the distribution piping to hose stations and spray systems in the flow path and would not reveal any obstructions to flow in that piping. For each test, static pressure (no flow) is compared to the line pressure at test flow. Although the acceptance criteria for tests are location specific, an acceptance criterion of 20 [pounds per square inch differential] psid is typical. Test results are trended to identify if any corrective actions are required to maintain the design flowrates at these hydraulically limiting locations. Currently, all of these tests are performed in the same year. The Fire Water System program will be enhanced to schedule the performance of these tests such that a portion of the tests are performed each year throughout the 5-year cycle.
- Hose station flow and shutoff valve tests for each hose station are performed every 3 years and consist of verifying hose station valve operability and flow through the connection with no indication of obstruction. This testing is performed on a total of 144 hose stations distributed throughout each of the reactor and turbine enclosures, as well as the control and radwaste enclosure. In addition, three more hose stations in the turbine enclosures are tested on a refuel cycle frequency since they are not accessible during plant operation. These tests identify flow obstructions in the fire system piping and demonstrate that there are no significant changes in the condition of the piping system that could result in loss of intended function.
- The Fire Water System program will be enhanced to perform a representative sample of main drain tests on an annual basis. A main drain test will be performed in each of the reactor and turbine enclosures, as well as the control and radwaste enclosure. When there is a 10-percent reduction in full flow pressure compared to the original test or previously performed tests, the issue will be entered into the corrective action program for evaluation.

The staff reviewed this exception to NFPA 25 Section 13.2.5. Although the applicant has not proposed to perform a main drain test at each riser, the staff finds the exception and program acceptable because the proposed alternative and reduced scope main drain testing is sufficient to establish reasonable assurance that flow blockage will be detected prior to a CLB intended function not being met for the period of extended operation. The staff based this conclusion on: (a) the alternative flow tests, both in number and scope of locations, provide insights concerning potential accumulation of corrosion products that are comparable to those gained from conducting the main drain tests recommended in LR-ISG-2012-02 AMP XI.M27; (b) the number of tests the applicant has proposed to perform (an average of 59 flow-related tests a year) which far exceeds the maximum of 25 inspections cited in random sampling programs recommended in GALL Report AMPs XI.M32, XI.M33, and XI.M38; and (c) the flow-related tests include six annual main drain tests; and (d) the scope of testing, which will encompass piping located in six different buildings.

_Valves and System-Wide Testing—Deluge Valves_. The staff noted that NFPA 25, Sections 13.4.3.2.2 through 13.4.3.2.5, recommend that each deluge valve be trip tested annually at full flow. The staff also noted that NFPA 25 allows that, where the nature of the protected property is such that water cannot be discharged unless protected equipment is shut down (e.g., energized electrical equipment), a full flow system test can be conducted at the next scheduled shutdown, not to exceed 3 years. NFPA 25 also allows that, where the nature of the protected property is such that water cannot be discharged, the nozzles or open sprinklers are inspected for correct orientation and the system tested with air to ensure that the nozzles are not obstructed.

The applicant stated that there are 32 fire water deluge systems at the station, which vary in frequency of testing from an annual test to every 3 years. Fifteen of the systems are flow tested with water. Thirteen of the systems are flow tested with air. The remaining four systems are not part of the NRC-approved fire protection program and are not flow tested. The Fire Water System program will be enhanced to perform air testing on these four systems every 2 years. Visual inspections associated with the testing ensure that the patterns are not impeded by plugged nozzles. The fire water system also includes 19 deluge systems that are associated with heating ventilation and air conditioning system charcoal filters. The Fire Water System program will be enhanced to perform the charcoal filter deluge valve exercise testing and air flow nozzle testing on a refueling cycle frequency.

The staff finds the applicant's program, with enhancement, acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

_Water Spray Fixed Systems—Strainers_. The staff noted that NFPA 25, Sections 10.2.1.6, 10.2.1.7, and 10.2.7, as modified by LR-ISG-2012-02 AMP XI.M27, recommend removal, inspection, and cleaning of fire water system strainers after each actuation and every refueling outage interval. The applicant stated that the fire water system includes line strainers on the supply to several deluge headers for plant equipment. The Fire Water System program will be enhanced to inspect and clean these strainers after each deluge system actuation. Line strainers to deluge systems that are subject to full flow tests will be inspected and cleaned on a frequency consistent with the deluge system test frequency. The applicant also stated that cleaning strainers more frequently than the testing frequency does not provide any meaningful information about the condition of the deluge and fire water system piping since the only time the strainer has flow is during testing.

The staff reviewed this exception to inspecting strainers every refueling outage interval and the staff finds the exception and program acceptable because debris will not accumulate on the screens when there is no flow and the applicant will inspect the strainers after each actuation of the deluge system.

_Water Spray Fixed Systems—Operation Test_. The staff noted that LR-ISG-2012-02 AMP XI.M27, states that testing spray nozzle discharge patterns on a refueling outage interval is one acceptable way to ensure that there are no obstructions to the discharge patterns. The staff also noted that NFPA 25 Section 10.3.4.3 and LR-ISG-2012-02 AMP XI.M27 include a provision to allow for testing with air where water cannot be discharged due to the nature of the protected property. The applicant stated that, with the exception of the transformer deluge systems, the spray systems are located in areas where water cannot be discharged without impacting the protected property and critical equipment. The applicant also stated that:

- Air flow testing of dry pipe preaction spray headers to confirm no obstructions to flow will be conducted at a frequency of 3 years.
- Air flow testing of open deluge nozzles to confirm no plugged nozzles will be conducted at a frequency of 3 years.
- Air flow testing of deluge systems nozzles for charcoal filter systems to confirm no plugged flow nozzles will be conducted whenever the charcoal filter media is replaced. However, the Fire Water System program will be enhanced to perform air flow testing of the charcoal filter deluge systems every refueling interval.
- Water flow testing of transformer deluge nozzles to confirm no obstructions to flow will be conducted. The main power and auxiliary transformers are tested on a refueling cycle frequency and other transformer deluge systems are tested every 3 years.
- Water flow testing of wet pipe sprinkler systems spray headers to confirm the headers do not have any flow obstructions will be conducted at least every 18 months.

The staff noted that some of the inspection frequencies exceed a refueling outage interval. The staff also noted that the applicant did not provide a basis for the longer inspection intervals (e.g., plant-specific OE, alternative testing). By letter dated April 24, 2014, the staff issued RAI 3.0.3.3.3-3 requesting that the applicant state the basis for the longer inspection intervals associated with some water spray fixed systems operational testing.

In its response dated May 21, 2014, the applicant stated that the existing testing frequency is consistent with the NRC-approved fire protection program described in the plant-specific Technical Requirements Manual. The dry-pipe preaction spray headers are pressurized with dry instrument air. The applicant also stated that a review of testing conducted since 2000 (210 air flow tests for dry-pipe preaction systems and 84 air flow tests for deluge systems) revealed only one instance of flow obstruction (February 2002). The applicant further stated that there are nine deluge systems associated with the main power and auxiliary transformers that are tested on a refueling cycle interval. There are six deluge systems associated with transformers for the offsite power distribution system for both reactor units. The Technical Specifications require that each reactor unit maintain two independent, physically separated, circuits between the offsite and onsite distribution systems. The applicant stated that the 3-year testing frequency of these six deluge systems balances offsite power availability and reliability of the equipment.

The staff noted that NFPA 25 (2011 Edition) Section 13.4.3.2.2.4 states that full flow testing [preaction valves and deluge valves] shall not exceed 3 years. The staff finds the applicant's response and program for the dry pipe preaction spray headers acceptable because the likelihood of loss of material that could result in flow blockage is very low in a dry air environment and only 1 test out of 210 revealed a flow obstruction, with subsequent testing since February 2002 not revealing any obstructions, and therefore a 3-year interval of testing is acceptable. The staff finds the applicant's response and program for the deluge systems acceptable because they are either tested on a refueling outage interval, which is consistent with LR-ISG-2012-02 AMP XI.M27, or for those tested on a 3-year interval: (a) the applicant provided a reasonable availability versus reliability justification, (b) plant-specific OE demonstrates a low likelihood of flow blockage, and (c) NFPA 25 allows a maximum 3-year interval for testing. The staff's concern described in RAI 3.0.3.3.3-3 is resolved.

*Foam Water Sprinkler Systems—Strainers*. The staff noted that NFPA 25 Section 11.2.7.1, as modified by LR-ISG-2012-02 AMP XI.M27, recommends removal, inspection, and cleaning of foam water sprinkler system strainers after each actuation and every refueling outage interval. The applicant stated that the fire water system includes a foam system to provide fire protection for the fuel oil storage tank. The system is flow tested annually. The water supply line to the foam system includes a Y-strainer which is currently cleaned every 5 years concurrent with foam tank cleaning. The Fire Water System program will be enhanced to include inspection and cleaning of the foam water supply strainer after each foam system test or actuation and no less frequently than once per refueling interval.

The staff finds the applicant's program acceptable because, with enhancement, it is consistent with LR-ISG-2012-02 AMP XI.M27.

*Foam Water Sprinkler Systems—Operational Test Discharge Patterns*. The staff noted that NFPA 25 Section 11.3.2.6, as modified by LR-ISG-2012-02, recommends an annual operational discharge test of foam water sprinkler systems to ensure that spray nozzles are not obstructed. Where the nature of the protected property is such that foam cannot be discharged, the nozzles are inspected for correct orientation and the system tested with air to ensure the nozzles are not obstructed. The applicant stated that the fire water system:

> includes a foam system that discharges foam inside the fuel oil storage tank in the event of a fire. In this application, the foam cannot be discharged into the tank containing fuel oil to verify the foam nozzle is not obstructed for test purposes. A foam system flow test is performed annually which demonstrates the flow path for foam to the top of the fuel oil tank is unobstructed. The annual test also verifies that the foam hose reel station flow path is unobstructed. The flow path for the foam into the fuel oil tank interior includes a fixed foam maker and does not include spray nozzles. The foam maker is an air-aspirating discharge device designed to provide the required rate of foam solution with an air inlet to generate expanded foam. There are no small openings, similar to a nozzle, which could clog from corrosion products on the foam supply. As such, an air test of the foam maker to confirm no obstructions does not provide relevant information to assess the condition of the foam system piping.

The staff reviewed the applicant's test method and the exception to checking for nozzle obstruction and finds it acceptable because the flow test is capable of detecting obstructions, there are no small openings in the foam maker discharge device that could become blocked by corrosion products, the water supply Y-strainer is inspected on an annual basis (as described above) and these inspections are capable of detecting corrosion product accumulation, and the test is conducted annually.

*Foam Water Sprinkler Systems—Storage Tanks*. The staff noted that LR-ISG-2012-02 AMP XI.M27 recommends that an internal visual inspection for corrosion be conducted every 10 years for foam water sprinkler system storage tanks. The applicant stated that the Fire Water System program currently performs a tank internal inspection at least every 10 years.

The staff finds the applicant's program acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

_Obstruction Investigation—Obstruction, Internal Inspection of Piping_. The staff noted that NFPA 25 Sections 14.2 and 14.3 provide recommendations for internal inspections of sprinkler piping. The applicant stated that the fire water system includes three types of sprinkler systems: wet pipe systems, dry pipe preaction systems, and deluge systems. The staff's evaluation of the applicant's proposal for each of these follows:

- Wet pipe sprinkler systems: The applicant stated that there are 31 wet pipe systems that are constantly filled with water and not subject to intermittent wet and dry conditions. Water flow testing of wet pipe sprinkler systems spray headers to confirm the headers do not have any flow obstructions is performed at least every 18 months by passing flow through the headers and system inspector's test valve downstream of the sprinkler heads. A review of flow test results for the past 10 years did not reveal any instances of flow obstructions or blockage resulting from corrosion of internal surfaces. Draining water from the piping to allow visual internal inspections introduces a fresh supply of oxygen to support the corrosion process. In addition, the wet pipe sprinkler systems are each constructed of the same materials and exposed to the same process conditions and environments. Therefore, rather than drain all sprinkler systems every 5 years to perform internal inspections as recommended in LR-ISG-2012-02, the Fire Water System program will be enhanced for wet pipe sprinkler systems as follows: (a) solids discharged from the wet pipe sprinkler systems through the inspector's test valve during flow testing will be collected and evaluated, and abnormal discharge or indication of obstructed flow will be entered into the corrective action program for evaluation; (b) visual internal inspections for corrosion and obstructions to flow will be performed on a 5-year frequency consistent with NFPA 25 with 5 of the 31 wet pipe sprinkler systems being selected for these internal inspections; and (c) an internal visual inspection will be performed after any wet pipe sprinkler system actuation prior to return to service.

  The staff notes that introducing fresh water into a wet pipe sprinkler system does introduce new supplies of oxygen which can promote corrosion, and therefore, alternative tests and inspections could result in less corrosion in the system. The staff finds the applicant's exception to NFPA Section 14.2, with enhancements to the program, acceptable because: (a) flow tests are capable of detecting gross obstructions or blockage; (b) plant-specific results of flow testing to date have not revealed any instances of flow obstructions or blockage; (c) collecting solids discharged through the inspector's test valve during flow testing will reveal any loose transportable corrosion products which can be addressed by the corrective action program; and (d) given that the internal environment is reasonably uniform throughout the system, the five internal inspections conducted in accordance with NFPA 25 would be capable of detecting fixed corrosion that could be causing obstructions and blockage (e.g., tubercules).

- Dry pipe preaction sprinkler systems: The applicant stated that there are 38 dry pipe preaction sprinkler systems that are normally dry and filled with pressurized air until actuated. The design for the preaction systems provides station instrument air to maintain the dry pipe preaction spray headers pressurized using dry air with a dew point normally less than −40 °F. The dry pipe preaction sprinkler systems are not periodically tested with water. Therefore, the dry pipe preaction sprinkler systems are not subject to intermittent wet and dry conditions that promote corrosion of internal surfaces. The preaction water control valves are periodically serviced every refueling interval resulting in access to the spray header internal surfaces. The Fire Water System program will be enhanced to perform the following for dry pipe preaction sprinkler systems: (a) an internal visual inspection for evidence of corrosion and flow obstruction of the internal surfaces made accessible during the deluge valve maintenance activity every refueling interval, and (b) an internal visual inspection after any dry pipe preaction sprinkler system actuation prior to return to service.

The staff finds the applicant's exception to NFPA Section 14.2 and enhancements to the program acceptable because: (a) consistent with GALL Report item AP-4, there is a very low likelihood of loss of material occurring on the internal surfaces of steel pipe exposed to dry air; and (b) given that the internal environment is reasonably uniform throughout the system, the visual inspections of surfaces made accessible during deluge valve maintenance would provide insights into whether flow blockage existed in any portions of the system.

- Deluge systems: The applicant stated that there are 51 deluge systems that are normally exposed to building air at atmospheric pressure. With the exception of the deluge systems for plant transformers, the deluge systems are not flow tested with water. The transformer deluge systems are periodically flow tested with water through the spray nozzles on either a 2-year or 3-year interval. Other deluge systems are not periodically tested with water and are not subject to intermittent wet and dry conditions that promote corrosion of internal surfaces. These deluge systems are air flow tested on a frequency of either 2 or 3 years to confirm that there are no obstructions to flow. Deluge valves that are automatically actuated are periodically serviced at least every 3 years resulting in access to the spray header internal surfaces. The Fire Water System program will be enhanced to perform the following for deluge systems: (a) perform an internal visual inspection for evidence of corrosion and flow obstruction on a representative sample of deluge systems of the internal surfaces made accessible during the valve maintenance activity every 3 years; (b) the representative sample will include inspection of at least 10 of the 51 deluge systems; and (c) perform an internal visual inspection after any deluge system actuation prior to return to service.

  The staff noted that for steel piping exposed to uncontrolled indoor air, GALL Report items E-25, E-29, and EP-42 recommend that loss of material be managed by GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." AMP XI.M38 recommends that for each material, environment, and aging effect combination, 20 percent of the components (with a maximum of 25) should be inspected in each 10-year interval of the period of extended operation. The staff also noted that the applicant proposed to inspect a representative population of virtually 20 percent every 3 years. The staff finds the applicant's exception to NFPA Section 14.2, and enhancements to the program, acceptable because: (a) the deluge systems are subjected to flow testing which could detect the presence of corrosion products that are not fixed; (b) given that the internal environment is reasonably uniform throughout the system, the internal inspection of a representative sample of 10 of the 51 deluge systems every 3 years would provide insights into whether flow blockage existed in any portions of the system.

In summary, the staff finds that the proposed testing in accordance with NFPA 25 and alternative tests are sufficient to provide reasonable assurance that obstructions and blockage would be detected in the wet pipe systems, dry pipe preaction systems, and deluge systems.

The applicant also stated that, if degraded conditions are identified, the CAP will be used to perform an obstruction evaluation and determine the extent of condition and need for increased inspections. The staff finds this acceptable because it is consistent with NFPA 25 Section 14.3 (e.g., Section 14.3.1, items 2, 4), as recommended by LR-ISG-2012-02 AMP XI.M27.

In addition to addressing each of the 16 recommended inspections and tests listed in LR-ISG-2012-02 AMP XI.M27 Table 4a, the applicant stated the following:

- The Fire Water System program will be enhanced to perform internal visual inspections described above to identify internal corrosion and obstructions to flow. If degraded conditions are identified, the corrective action program will be used to perform an obstruction evaluation and determine the extent of condition and need for increased inspections.

  The staff found this acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

- The Fire Water System program will be enhanced to conduct followup volumetric inspections if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal wall thickness.

  The staff found this acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

- As the result of industry operating experience, the sprinkler system piping configurations were reviewed and walkdowns were performed in 2012 to confirm that the piping was suitably sloped for drainage after system actuations or testing. The Fire Water System program will be enhanced to state that 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, if required, will be performed in each 5-year interval beginning 5 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 5-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.

  The staff found this acceptable because it is consistent with LR-ISG-2012-02 AMP XI.M27.

The staff noted that LRA Section B.2.1.18 was amended to reflect the addition of Enhancement Nos. 3 through 9, as described above. The program was also enhanced (Enhancement No. 10) to address recurring internal corrosion in the backup fire water piping. The staff's evaluation of this enhancement is documented in SSER Section 3.0.3.3.1.

<u>UFSAR Supplement</u>. The staff reviewed the changes to the UFSAR supplement description of the program as amended by letter dated March 12, 2014, and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1 as revised by LR-ISG-2012-02. The staff also noted that the enhancements described above are reflected as changes to Commitment No. 18.

Conclusion. On the basis of its review of the proposed changes to the Fire Water System program as amended by letters dated March 12, 2014, and May 21, 2014, the staff determines that those program elements for which the applicant claimed consistency with LR-ISG-2012-02 AMP XI.M27 are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMP, with the exceptions, is adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 18 prior to the period of extended operation will make the AMP adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

#### 3.0.3.3.4 Aboveground Metallic Tanks

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review and changes to the LRA associated with the staff's recommendations in LR-ISG-2012-02 Section D, "Revisions to the Scope and Inspection Recommendations of GALL Report AMP XI.M29," and associated appendices. The staff's evaluation of the applicant's revisions follows.

Staff Evaluation. To insure that the aging effects associated with tank surfaces are properly age managed, the staff revised its guidance (LR-ISG-2012-02, Section D, "Revisions to the Scope and Inspection Recommendations of GALL Report AMP XI.M29") to include periodic internal visual examinations and surface inspections on the external surfaces of in-scope tanks. The revised guidance provided specific recommendations for inspection technique and frequency for tank surfaces depending on material, environment, and the applicable aging effect requiring management (AERM). In addition, the revised guidance included certain indoor large-volume tanks (e.g., greater than 100,000 gallons). The revised guidance also specifically excluded firewater storage tanks from the scope of GALL Report AMP XI.M29 and recommended use of GALL Report AMP XI.M27, as revised by LR-ISG-2012-02.

By letter dated March 12, 2014, the applicant revised LRA Sections A.2.1.19, B.2.1.19, and Commitment No. 19 for its Aboveground Metallic Tanks program, to address the staff's recommendations as described in LR-ISG-2012-02 Section D.

In its letter dated March 12, 2014, the applicant stated that it does not have any indoor tanks that meet the staff's updated guidance for inclusion into the Aboveground Metallic Tank GALL Report AMP XI.M29. The staff reviewed the applicant's LRA and UFSAR and did not note any indoor storage tanks (e.g., greater than 100,000 gallons), that are in the scope of the revised GALL Report AMP XI.M29. The applicant also stated that it will continue to maintain the backup [fire] water storage tank in the scope of its Aboveground Metallic Tanks program. The staff's evaluation of the inclusion of the backup water storage tank and associated changes to LRA Sections A.2.1.19 and B.2.1.19 and Commitment No. 19 is documented in SSER Section 3.0.3.3.3.

#### 3.0.3.3.5 Corrosion Under Insulation

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review and changes to the LRA associated with the staff's recommendations in LR-ISG-2012-02 Section E, "Corrosion Under Insulation" (CUI) and associated appendices. The staff's evaluation of the applicant's revisions follows.

Staff Evaluation. To insure that loss of material and cracking underneath insulation are properly age-managed, the staff revised its guidance (LR-ISG-2012-02 Section E) to include the recommendation for examining surfaces underneath insulation and the condition of insulation jacketing. The recommended changes resulted in revisions to GALL Report AMPs XI.M29 and XI.M36, "Aboveground Metallic Tanks" and "External Surfaces Monitoring of Mechanical Components," respectively. The revised guidance included recommendations to periodically (each 10-year period) inspect 20 percent of each population of in-scope components, with a maximum sample size of 25, during the period of extended operation. In addition, the revised guidance recommended that inspection locations be based on the likelihood of CUI occurring.

The applicant revised LRA Sections A.2.1.25, B.2.1.25, and Commitment No. 25 for its External Surfaces Monitoring of Mechanical Components program to address the staff's recommendations to manage CUI as described in LR-ISG-2012-02 Section E. The staff's evaluation of the applicant's revisions to its Aboveground Metallic Tanks program is documented in SSER Sections 3.0.3.3.3 and 3.0.3.3.4.

In its letters dated March 12, 2014, and May 21, 2014, the applicant stated that its External Surfaces Monitoring of Mechanical Components program will be revised to include a sample of outdoor component surfaces, except tanks, that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component's being operated below the dewpoint). The sample size consists of a minimum of 20 percent of the in-scope piping length for each material type (i.e., steel, stainless steel, copper alloy, and aluminum), or, for components with configurations that do not conform to a 1-foot axial length determination (e.g., valves, accumulators), 20 percent of the surface area. An alternative approach is to remove the insulation and inspect any combination of a minimum of twenty-five 1-foot axial length sections and components for each material type. For indoor tanks, insulation will be removed from either twenty-five 1-square-foot sections or 20 percent of tanks surface area. Inspections will be conducted in each air environment (e.g., air-outdoor, moist air) in which condensation or moisture on the surfaces of the component could occur routinely or seasonally. Tank sample inspection points are distributed in such a way that inspections occur on the tank dome and sides, near the bottom, at points where structural supports or instrument nozzles penetrate the insulation, and where water might collect, such as on top of stiffening rings. The applicant also stated that these under-the-insulation inspections will be performed every 10 years during the period of extended operation. The applicant further stated that inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material beyond that which could have been present during initial construction and no evidence of cracking. However, if the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation, then periodic under-insulation inspections to detect CUI will continue.

The applicant stated that the program does not require removal of tightly adhering insulation that is impermeable to moisture unless there is evidence of damage to the moisture barrier. The applicant stated that, instead, the program includes visual inspection of the entire accessible population of piping and components during each 10-year period of the period of extended operation.

The staff finds the applicant's LRA revisions to its External Surfaces Monitoring of Mechanical Components program acceptable because the applicant's revisions to its inspection locations, sample size, methodology, and frequency are consistent with the staff's inspection and sampling recommendations of AMP XI.M36, as revised by LR-ISG-2012-02.

UFSAR Supplement Changes. The staff reviewed the changes to the UFSAR supplement description of the program as amended by letters dated March 12, 2014, and May 21, 2014, and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1, as revised by LR-ISG-2012-02. The staff noted that the revision (inclusion of cracking) described in LRA Sections A.2.1.25, and B.2.1.25 was not incorporated into Commitment No. 25. The staff accepts this minor oversight because the UFSAR supplement includes a statement that the applicant must confirm that cracking is not present during the initial representative bare metal inspections under insulation in order to conduct future inspections of the insulation external surface in lieu of removing insulation. The UFSAR supplement would be used to evaluate the acceptability of future procedure changes.

Conclusion. On the basis of its review of the proposed changes to the External Surfaces Monitoring of Mechanical Components program as amended by letters dated March 12, 2014, and May 21, 2014, the staff determines that those program elements for which the applicant claimed consistency with LR-ISG-2012-02 AMP XI.M36 are consistent. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplement for this AMP and concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.3.6 External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review of the changes regarding managing the aging effects associated with internal surfaces of underground piping in LR-ISG-2012-02 Section F, " External Volumetric Examination of Internal Piping Surfaces of Underground Piping Removed from GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks" and associated appendices."

Staff Evaluation. The staff noted that LR-ISG-2012-02 Section F revises GALL Report AMP XI.M38 to allow for the condition of the internal surfaces of buried and underground piping being assessed based on inspections of the interior surfaces of accessible piping where the material, environment, and aging effects are similar for both the accessible and the buried or underground components.
The applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program does not include any components in which this situation is applicable. Therefore, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is retained as described in the LRA Sections A.2.1.26 and B.2.1.26, LRA Table A.5 Commitment No. 26, and SER Section 3.0.3.1.16. Volumetric inspections of underground piping will remain part of the Buried and Underground Piping and Tanks program

described in LRA Sections A.2.1.29 and B.2.1.29, LRA Table A.5 Commitment No. 29, and SER Section 3.0.3.2.12.

The staff finds the applicant's proposal acceptable because the Buried and Underground Piping and Tanks program, Enhancement Nos. 3 and 4 adequately manage loss of material on the internal surfaces of underground piping by using volumetric examinations.

Conclusion. The staff has concluded that no changes are required to either the Internal Surfaces in Miscellaneous Piping and Ducting Components program or the Buried and Underground Piping and Tanks program. The programs are adequate to manage the applicable aging effects.

3.0.3.3.7 Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review of the changes regarding managing aging effects associated with elastomers in LR-ISG-2012-02 Section G, "Specific Guidance for Use of the Pressurization Option for Inspecting Elastomers in GALL Report AMP XI.M38," and associated appendices.

Staff Evaluation. The staff noted that LR-ISG-2012-02 Section G revises GALL Report AMP XI.M38 to provide guidance for the inspection of elastomers by pressurization.

The applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program performs inspection of elastomeric materials with the manipulation option, as described in GALL Report AMP XI.M38. The pressurization option is not used. Therefore, there is no change to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting program for this issue.

The staff finds the applicant's proposal acceptable because physical manipulation is an adequate method to detect hardening and loss of strength in elastomers.

Conclusion. The staff has concluded that no changes are required to the Internal Surfaces in Miscellaneous Piping and Ducting Components program. The program is adequate to manage the applicable aging effects.

3.0.3.3.8 Key Miscellaneous Changes to the GALL Report and SRP-LR

Summary of Changes. By letter dated March 12, 2014, the applicant provided the results of its review of the changes regarding managing aging effects associated with key miscellaneous changes in LR-ISG-2012-02 Section H, "Key Miscellaneous Changes to the GALL Report and SRP-LR," and associated appendices.
Staff Evaluation. The staff noted that LR-ISG-2012-02 Section H addressed several miscellaneous changes to the GALL Report and SRP-LR. The staff's evaluation of the applicant's review of each follows:

*Revised Definition of Hardening and Loss of Strength*. The staff noted that the definition of "hardening and loss of strength" in Section IX.E of the GALL Report was revised to replace the term "weathered" with the term "degraded" because weathering is generally associated with aging as a result of contact with outdoor weather conditions. In addition, cracking and loss of sealing were added to the examples associated with degraded elastomers. These changes provided a more complete list of aging effects and result in the definition's being more consistent with program element 3, "parameters monitored or inspected," of GALL Report AMP XI.M38. Likewise, program element 3, "parameters monitored or inspected," of GALL Report AMP XI.M38 was revised to include loss of sealing.

The applicant stated that the aging management activities in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components are sufficient to identify the applicable aging mechanism for elastomers. No changes to the LRA or the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are required to address this issue.

The staff noted that, based on its review of the LRA AMR items citing hardening and loss of strength as an aging effect (e.g., flexible connections, hoses, expansion joints, fire barriers), three more programs than stated by the applicant are used to manage the aging effect, including the Open-Cycle Cooling Water System, Fire Protection, and External Surfaces Monitoring of Mechanical Components programs. The staff finds the applicant's proposal (i.e., no changes to the LRA) acceptable because the revised definition did not change the intent of the inspections of elastomeric materials for these programs.

*Revised Definition of Elastomer Degradation*. The staff noted that the definition of elastomer degradation in Section IX.F of the GALL Report was revised to include change in material properties as an aging effect example to make the definition more consistent with program element 3, "parameters monitored or inspected," of GALL Report AMP XI.M38.

The applicant stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program utilizes the elastomer manipulation option for inspecting elastomeric components, which is appropriate to detect change in material properties. No changes to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting program are required to address this issue.

The staff noted that, based on a review of the LRA AMR items associated with elastomer degradation, many more programs than stated by the applicant are used to manage the associated aging effects (e.g., hardening and loss of strength). Examples other than those cited in the above change include the Structures Monitoring, Metal Enclosed Bus, and 10 CFR Part 50 Appendix J programs. The staff finds the applicant's proposal (i.e., no changes to the LRA) acceptable because the revised definition did not change the intent of the inspections of elastomeric materials for these programs.

*Alternative AMP for Inspection of Polymeric Components*. The staff noted that the LR-ISG clarified GALL Report AMP XI.M38 to allow internal surfaces of polymers to be inspected from the external surface when the material and environment combinations are the same.

The applicant stated that the external environment of those elastomers within the Internal Surfaces in Miscellaneous Piping and Ducting Components program is the air-indoor, uncontrolled environment. There are no LRA AMR items that utilize the air-indoor, uncontrolled environment as the internal environment for any elastomer in this program, and therefore this provision is not applicable.

The staff finds the applicant's proposal (i.e., no changes to the LRA) acceptable because the change only clarified the GALL Report AMP XI.M38 to allow an alternative to internal surface inspections that already existed in GALL Report AMP XI.M36, “External Surfaces Monitoring of Mechanical Components.”

*Revised Definition of Fouling*. The staff noted that the GALL Report definition of fouling was revised to be more reflective of the discussions in LR-ISG-2012-02 related to flow blockage of water-based fire protection system piping. Specifically the terms “flow or pressure” were added as consequences of fouling to the existing terms “reduction of heat transfer and loss of material.”

The applicant stated that the expanded definition of fouling does not impact the LRA and fouling caused by flow blockage specific to the fire protection systems is addressed in its response to Section C of LR-ISG-2012-02.

The staff finds the applicant’s proposal (i.e., no changes to the LRA) acceptable because potential flow blockage was adequately addressed by enhancements to the Fire Water System program described in SSER Section 3.0.3.3.3.

*High-Density Polyethylene Components*. The staff noted that the SRP-LR and GALL Report were revised to add an AMR item for high-density polyethylene (HDPE) piping exposed to an underground environment.

The applicant stated that the additional AMR item does not impact the LRA because it does not have in-scope HDPE piping.

The staff evaluated the applicant’s claim and finds it acceptable because the staff’s review of the LRA and UFSAR found that the applicant has no in-scope HDPE piping.

*Waste Water Environment*. The staff noted that the SRP-LR and GALL Report were revised to include waste water as an applicable environment for an existing AMR item, 3.3.1-72, associated with selective leaching.

The applicant stated that, while the revised item does apply to their site, the LRA already appropriately addresses selective leaching of gray cast iron in waste water in LRA Table 3.3.2-13. No changes to the LRA are required.

The staff evaluated the applicant’s proposal (i.e., no changes to the LRA) and finds it acceptable because, as documented in SSER Section 3.3.2.3.13, the applicant has appropriately addressed selective leaching of gray cast iron in waste water by managing this aging effect with the Selective Leaching program, which is consistent with LR-ISG-2012-02.

*Components Exposed to Raw Water that Are Not Covered by NRC Generic Letter (GL) 89-13*. The staff noted that the SRP-LR and GALL Report were revised to add AMR items for components exposed to raw water that are not covered by NRC GL 89-13, “Service Water System Problems Affecting Safety-Related Equipment.” The new AMR items recommend GALL Report AMP XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components.”

The applicant stated that the LRA already contains nonsafety-related components not covered by NRC GL 89-13 that are within the scope of the LGS Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. No changes in the LRA are required.

The staff evaluated the applicant's proposal (i.e., no changes to the LRA) and finds it acceptable because, as documented in SER Section 3.3.2.1.8, the applicant has appropriately addressed loss of material for components not covered by NRC GL 89-13 by managing this aging effect with the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, which is consistent with LR-ISG-2012-02.

*Managing Loss of Material on the Internal Surfaces of Submerged Pump Casings*. The staff noted that the SRP-LR and GALL Report were revised to allow the use of GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to manage loss of material on the internal surfaces of submerged pump casings exposed to waste water, as long as the material and environment combinations are the same for the internal and external surfaces.

The applicant stated that the situation of submerged pumps in a waste water environment is not applicable at LGS. No changes to the LRA are required.

The staff evaluated the applicant's claim and finds it acceptable because the staff's review of the LRA and UFSAR found that the applicant has no submerged pumps exposed externally to waste water.

*Jacketed Insulation*. The staff noted that the SRP-LR and GALL Report were revised to add jacketed insulation exposed to outdoor air and uncontrolled indoor air being managed with GALL Report AMP XI.M36 for degradation of thermal insulation due to moisture intrusion.

Changes to the LRA to address degradation of thermal insulation and the staff's acceptance of the applicant's proposal are documented in SSER Section 3.5.2.3.10.

Conclusion. The staff concludes that the applicant has adequately addressed the changes described in LR-ISG-2012-02 Section H.

#### *3.0.3.4 Aging Management Related to Loss of Coating Integrity for Internal Coatings on In-Scope Mechanical SSCs*

Summary of Changes. Based on reviews of LRAs and industry OE conducted by the staff, the staff identified an issue concerning loss of coating integrity of internal coatings of piping, piping components, heat exchangers, and tanks. By letter dated February 10, 2014, the staff issued RAI 3.0.3-1, requesting that the applicant address several questions associated with managing loss of coating integrity associated with coatings installed on the internal surfaces of in-scope piping, piping components, heat exchangers, and tanks. The staff's evaluation of the response follows.

Staff Evaluation. Based on reviews of LRAs and industry OE conducted by the staff, the staff has determined that additional recommendations beyond those in the GALL Report are appropriate to manage loss of coating integrity for internal coatings of piping, piping components, heat exchangers, and tanks. The staff has concluded that the following recommended actions provide one acceptable approach for managing the associated aging effects for components within the scope of license renewal. Throughout the remainder of this SSER section, the phrase "staff's recommended actions to manage loss of coating integrity" refers to this subsection of the SSER.

- Periodic visual inspections of coatings to detect blistering, cracking, flaking, peeling, delamination, rusting, spalling (for cementitious coatings), and physical damage should be conducted. For purposes of license renewal, physical damage would be limited to age-related mechanisms such as that occurring downstream of a throttled valve as a result of cavitation versus damage caused by inspection activities (e.g., chipping of the coating due to installation of scaffolding, removal and reinstallation of inspection ports). Inspections are conducted for each coating material and environment combination. The coating environment includes both the environment inside the component (e.g., raw water) and the metal to which the coating is attached.
- Baseline inspections should be conducted in the 10-year period prior to the period of extended operation. Subsequent inspections should be based on the results of these and follow-on inspections as follows:
  (a) If no peeling, delamination, blisters, or rusting are observed during inspections, and cracking, flaking, or spalling (in cementitious coatings) has been found acceptable, subsequent inspections should be conducted 6 years after the most recent inspection. Peeling, delamination, blisters, or rusting can be indicative of loss of adhesion that could result in the coating becoming debris or not being able to perform a corrosion deterrence function. Cracking, flaking, or spalling, although indicators of some degree of coating degradation, are not significant enough to require more frequent inspections as long as the condition has been found acceptable by qualified personnel. For example, despite cracking being found, the base metal could still be isolated from the environment and the coating retain sufficient integrity so as not to become debris.

  (b) If the prior inspection results do not meet (a) above and a coatings specialist has determined that no remediation is required, subsequent inspections should be conducted 4 years after the most recent inspection. More frequent inspections are warranted to confirm the coatings specialist’s evaluation. If two sequential subsequent inspections demonstrate no change in coating condition, subsequent inspections may be conducted at 6-year intervals.

  (c) Given that coatings in redundant trains are exposed to the same environment, the inspection interval may be extended to 12 years as long as: (a) the identical coating material was installed with the same installation requirements in redundant trains (e.g., piping segments, tanks) with the same operating conditions and at least one of the trains is inspected every 6 years, and (b) the coating is not in a location subject to turbulence that could result in mechanical damage to the coating.

  (d) Given that the coatings installed on the internal surfaces of diesel fuel oil storage tanks are generally exposed to a static environment, the inspection interval may be conducted in accordance with GALL Report AMP XI.M30, “Fuel Oil Chemistry,” as long as the inspection results meet (a) above.
- The extent of inspections should include all accessible tank and heat exchanger internal surfaces. The staff recognizes that, for piping, extensive amounts of coating could be installed. GALL Report AMPs such as XI.M38, “Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components,” are based on sampling a portion of the population. The staff has concluded that using a sampling-based extent of inspections is appropriate for coatings installed on the internal surfaces of piping. Where documentation exists that manufacturer recommendations and industry consensus

documents (i.e., those recommended in Regulatory Guide (RG) 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Plants” or earlier versions of those standards) were used during installation, the extent of piping inspections may be twenty-five 1-foot axial length circumferential segments of piping or 20 percent of the total length of each coating material and environment combination. This extent of sampling is consistent with several GALL Report AMPs. However, where documentation does not exist that manufacturer recommendations and industry consensus documents were used during installation, the staff has concluded that a larger extent of inspection is appropriate, consisting of seventy-three 1-foot axial length circumferential segments of piping or 50 percent of the total length of each coating material and environment combination. Regardless of the extent of inspections, the inspection surface includes the entire inside surface of the 1-foot sample. If geometric limitations impede movement of remote or robotic inspection tools, the number of inspection segments is increased to cover an equivalent length.

- The staff has concluded that, where loss of coating integrity cannot result in downstream effects such as reduction in flow, drop in pressure, or reduction in heat transfer for in-scope components, a representative sample of external wall thickness measurements can be used to confirm the acceptability of the corrosion rate of the base metal in lieu of visual inspections of the coating. The wall thickness measurements are an appropriate method to manage loss of coating integrity in this case because base metal corrosion is the only effect of loss of coating integrity.
- RG 1.54 (all revisions) describes the methods the staff considers acceptable for training and qualification of individuals involved in coating inspections and evaluating degraded conditions.
- A preinspection review of the previous two inspections should be conducted, including reviewing the results of inspections and any subsequent repair activities. A coatings specialist should prepare the post-inspection report to include: a list and location of all areas evidencing deterioration, a prioritization of the repair areas into areas that must be repaired before returning the system to service and areas where repair can be postponed to the next refueling outage, and where possible, photographic documentation indexed to inspection locations. When corrosion of the base material is the only issue related to coating degradation of the component and external wall thickness measurements are used in lieu of internal visual inspections of the coating, the corrosion rate of the base metal should be trended. These recommendations are consistent with ASTM D7167-05, “Standard Guide for Establishing Procedures To Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant,” which is referenced in RG 1.54.
- Based on the staff’s review of industry documents (e.g., ASTM, EPRI) the staff has concluded that, with the exception of Service Level I qualification testing, there are no acceptance criteria in recognized industry consensus documents. Acceptance of degraded coatings is established by the coatings specialist. RG 1.54 states that for Service Level I coatings: (a) peeling and delamination shall not be permitted, (b) cracking is not considered a failure unless it is accompanied by delamination or loss of adhesion, and (c) blisters shall be limited to intact blisters that are completely surrounded by sound coating bonded to the surface. The staff has established the following acceptance criteria for loss of coating integrity based on the recommendations in RG 1.54.

(a) Indications of peeling and delamination are not acceptable and the coating is repaired or replaced.

(b) Blisters can be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff guidance associated with use of a particular standard. Blisters should be limited to a few intact small blisters which are completely surrounded by sound coating bonded to the substrate. If the blister is not repaired, physical testing (e.g., lightly tapping the coating, adhesion testing) is conducted to ensure that the blister is completely surrounded by sound coating bonded to the surface. Acceptance of a blister to remain in service should be based both on the potential effects of flow blockage and degradation of the base material beneath the blister.

(c) If coatings are credited for corrosion prevention (e.g., corrosion allowance in design calculations is zero, the “preventive actions” program element credited the coating) and the base metal has been exposed or it is beneath a blister, the component’s base material in the vicinity of the degraded coating is examined to determine if the minimum wall thickness is met and will be met until the next inspection.

(d) Indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54, including staff guidance associated with use of a particular standard.

(e) Minor cracking and spalling of cementitious coating is acceptable provided there is no evidence that the coating is debonding from the base material.

(f) As applicable, wall thickness measurements meet design minimum wall requirements.

(g) Adhesion testing results, when conducted, meet or exceed the degree of adhesion recommended in engineering documents specific to the coating and substrate.

- Coatings that do not meet acceptance criteria should be repaired or replaced. Testing or examination is conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating material. These recommendations are consistent with ASTM D7167-05, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant,” which is referenced in RG 1.54.
- The staff has also concluded that the UFSAR supplement for the program(s) used to manage loss of coating integrity should include statements to the effect that: (a) the program consists of visual inspections of coatings, (b) for coated surfaces determined to not meet the acceptance criteria, physical testing should be performed where physically possible (i.e., sufficient room to conduct testing) with the test consisting of destructive or nondestructive adhesion testing using ASTM International Standards endorsed in RG 1.54, “Service Level I, II, and III Protective Coatings Applied to Nuclear Plants,” and (c) the training and qualification of individuals involved in coating/lining inspections should be conducted in accordance with ASTM International Standards endorsed in RG 1.54.

In its response dated March 14, 2014, the applicant stated that there are nine in-scope systems with internal coatings, including the reactor enclosure cooling water (RECW) heat exchangers, main control room (MCR) chiller condenser, circulating water system piping, cement-lined portions of the fire water system piping (buried yard mains), EDG diesel oil storage tanks, reactor core isolation cooling (RCIC) system turbine bearing pedestals and high-pressure coolant injection (HPCI) system turbine bearing pedestals and oil reservoir, galvanized portions of the fire water system (transformer deluge system piping, foam extinguishing system piping), galvanized portions of the plant drainage system (normal waste, oily waste, sanitary waste, and storm drain piping), and fire water system backup water storage tank.

The applicant stated that coating inspections are not required for the following:

- Galvanized portions of the fire water system (transformer deluge system piping and foam extinguishing system piping): the applicant stated that galvanized piping is not subject to unanticipated or accelerated corrosion of the base metal due to coating holidays. In the case of galvanized steel, since zinc has a lower electrode potential than steel, the zinc coating acts as a large sacrificial anode coupled with a small cathode where the steel substrate is exposed in the coating holiday. Since there is a relatively small cathode surface and a relatively large anode surface, there is no accelerated corrosion. In regard to flow blockage, a 10-year search of plant-specific operating experience did not reveal any issues with delamination, blistering, flaking, or peeling in the transformer deluge system and foam extinguishing system galvanized piping. The Fire Water System program, as amended by letter dated March 12, 2014 (review of LR-ISG-2012-02), includes flow testing of the transformer deluge systems and foam extinguishing system. The flow tests for the main and auxiliary transformers are performed every 2 years, and for the other transformers the flow tests are performed every 3 years. The foam extinguishing system is flow tested annually. These flow tests verify the absence of blockage which could occur due to coating failure.

  The staff acknowledges that the zinc-based coating would act as a sacrificial anode; however, there have been instances in the industry where the sacrificial coating has been consumed and the base metal corroded. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (1) requesting that the applicant state how it will determine that an adequate amount of the coating remains intact throughout the period of extended operation for the galvanized portions of the fire water system.

  In its response dated May 21, 2014, the applicant stated that the existing Fire Water System program enhancement associated with performing 10 internal visual inspections of the deluge systems to detect potential loss of material and flow obstructions was revised to state that 2 of the 10 inspections will be conducted on galvanized transformer deluge piping. These inspections will occur every 3 years.

  The staff finds the applicant’s response acceptable because, in addition to flow tests that will provide direct indication of potential flow blockage, the applicant will conduct periodic visual inspections that are capable of detecting potential loss of the galvanized coating and any associated loss of material. The staff’s concern described in RAI 3.0.3.4-1 Part (1) is resolved.

- Galvanized portions of the plant drainage system (normal waste, oily waste, sanitary waste, and storm drain piping): as stated above, galvanized piping is not subject to accelerated corrosion of the base metal caused by coating holidays. A 10-year search of plant-specific operating experience did not reveal any issues with delamination, blistering, flaking, or peeling in the galvanized normal waste, oily waste, and storm drain piping that could result in flow blockage. However, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, as amended by letter dated

March 12, 2014 (review of 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.

The staff noted that, in regard to unanticipated or accelerated corrosion of the base metal caused by coating holidays, based on a review of LRA Section 2.3.3.13, it is not likely that any of the in-scope components will be exposed to chemical compounds that could cause accelerated corrosion of the base material if coating degradation resulted in exposure of the base metal. The staff also noted that, as amended by letter dated March 12, 2014, the periodic inspections of a representative sample of each material, environment, and aging effect combination for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program can consist of inspecting components in a more severe environment. Given that the GALL Report definition of galvanized steel states, "[i]n the presence of moisture, galvanized steel is classified under the category 'Steel,'" it is not clear to the staff whether the applicant would select uncoated steel pipe in lieu of galvanized pipe in developing the scope of the representative sample of steel piping exposed to waste water. The staff noted that, depending on the characteristics of the waste water environment (e.g., alternating wetting and drying), portions of the galvanized piping may be most susceptible to corrosion; although alternatively, it could be viewed as not susceptible because of the galvanic coating. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (2) requesting that the applicant state whether the steel and galvanized steel portions of the plant drainage system (normal waste, oily waste, sanitary waste and storm drain piping) would be treated as two separate populations when determining a representative sample for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

In its response dated May 21, 2014, the applicant stated that steel and galvanized steel components exposed to a moisture environment will be considered as in the same population; however, 10 of the 25 inspections will be of the normal waste, oily waste, sanitary waste and storm drain galvanized piping, and 15 of the internal inspections will be of the radioactive floor and equipment drain carbon steel piping. The LRA program and UFSAR supplement were revised accordingly.

The staff noted that treating steel and galvanized steel components exposed to a moisture environment as a single population is consistent with the definition of galvanized steel in GALL Report Section IX.C. The staff finds the applicant's response and proposal to use the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of material acceptable because, during each 10-year period of the period of extended operation, a sufficient quantity of galvanized piping and steel piping will be visually inspected to provide insight into the internal conditions of the drain piping. The staff's concern described in RAI 3.0.3.4-1 Part (2) is resolved.

In regard to potential flow blockage, the staff finds the applicant's response and proposal to use the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage flow blockage acceptable because, although there is a low potential for flow blockage because galvanized coatings do not degrade in large cohesive sheets, the program will conduct periodic (not to exceed 10 years) internal visual inspections of a representative sample of the galvanized piping that are capable of ensuring that flow blockage does not occur.

The applicant also stated that the fire water system backup water storage tank internal coating is not addressed in the response to this RAI. The staff noted that the applicant addressed how loss of coating integrity would be managed for this tank in its response to LR-ISG-2012-02 dated March 12, 2014. The staff's evaluation of this response is documented in SSER Section 3.0.3.3.3.

*Inspection Methods and Parameters Monitored*. The applicant further stated that the coating inspection method will be visual inspections. Internal coatings will be inspected for signs of coating failures and precursors to coating failures including peeling, delamination, blistering, cracking, flaking, chipping, rusting, and mechanical damage. Coated surfaces that are accessible upon component disassembly or entry are visually inspected during each inspection interval. The staff finds the examination method, precursor indications, and extent of inspections acceptable because they are consistent with the staff's recommended actions to manage loss of coating integrity.

*Inspection Timing, Frequency and Extent*. The applicant stated that coating inspection activities will be included in the following programs and described the inspection timing, frequency, and extent as follows:

| Aging Management Program | Components |
|---|---|
| Open-Cycle Cooling Water System | RECW heat exchangers, MCR chiller condensers, circulating water system piping |
| Fire Water System | Cement-lined portions of the fire protection system piping (buried yard mains) |
| Fuel Oil Chemistry | EDG diesel oil storage tanks |
| Lubricating Oil Analysis | RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir |

- RECW Heat Exchangers. The service water side of these heat exchangers is internally coated with an epoxy coating, which is currently inspected at a 2-year frequency as part of the Open-Cycle Cooling Water System program. 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 within the scope of the rule under 10 CFR 54.4(a)(2) for spatial interaction only. The coatings were last inspected in April 2012 (1A), October 2013 (1B), January 2013 (2A), and April 2013 (2B). The 1A, 1B and 2A heat exchangers had coating degradation that required repair or replacement. The coating of 2B heat exchanger 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 2-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.

  The staff has concluded that one acceptable basis for alternative inspection frequencies would be to meet the following four conditions. The staff lacks sufficient information related to two of these four conditions (i.e., items 3 and 4 below).

(1) The staff noted that, based on a review of LRA Tables 3.0-1 and 3.3.2-12, it would not be expected that the nonsafety-related service water system would contain chemical compounds that could cause unanticipated or accelerated corrosion of the base material if coating degradation resulted in exposure of the base metal.

(2) The staff noted that the RECW heat exchangers are in scope for 10 CFR 54.4(a)(2) spatial interaction only.

(3) It is not clear to the staff whether the coated components are located in the vicinity of uncoated components that could cause a galvanic couple to exist.

(4) The staff does not know whether the corrosion allowance used for the RECW heat exchangers assumed that the component was not coated.

In addition to the open questions on items 3 and 4 above, the response to 3.0.3-1 did not state an upper limit on the period of time prior to a subsequent internal coating inspection for the RECW heat exchangers, MCR chiller condensers (see below) and circulating water system piping (see below) and incorporate this limit into the Open-Cycle Cooling Water System program, UFSAR supplement, and Commitment No. 12. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (3) requesting that the applicant provide the information on potential galvanic couple and corrosion allowance, state the maximum interval to subsequent coating inspections, and incorporate the inspection interval into the program, UFSAR supplement, and Commitment No. 12.

In its response dated May 21, 2014, the applicant stated that the maximum interval for subsequent inspections of the RECW heat exchangers, MCR chiller condensers and circulating water system piping will be consistent with draft LR-ISG-2013-01 AMP XI.M42, "Service Level III (augmented) Coatings Monitoring and Maintenance Program," Table 4a, "Inspection Intervals for Service Level III (augmented) Coatings for Tanks, Piping, and Heat Exchangers." The staff notes that draft LR-ISG-2013-01 was issued on January 6, 2014, ADAMS Accession No. ML13262A442. Commitment No. 12 was revised accordingly.

The staff noted that the draft LR-ISG-2013-01 Table 4a is consistent with the staff's recommended actions to manage loss of coating integrity and, therefore, the information related to potential galvanic couple and corrosion allowance is not required. The staff finds the applicant's response and proposed inspection frequency for the RECW heat exchangers, MCR chiller condensers and circulating water system piping acceptable because conducting baseline inspections in the 10-year period prior to the period of extended operation and the subsequent inspection intervals are consistent with the staff's recommended actions to manage loss of coating integrity; and revising Commitment No. 12 is sufficient to ensure that the AMP implementing documents will be revised appropriately. The staff's concern described in RAI 3.0.3.4-1 Part (3) is resolved.

- <u>MCR Chiller Condensers</u>. The service water side of these heat exchangers is internally coated with an epoxy coating, which is currently inspected by the Open-Cycle Cooling Water System program (as part of GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," program activities) at a 1-year frequency. These coatings are safety-related. The service water side of the MCR chiller condensers are within the scope of 10 CFR 54.4(a)(1). 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. Baseline inspections will occur in the 10-year period prior to the period of extended operation. As discussed above in the staff's evaluation of the RECW heat exchangers, the applicant has committed to perform subsequent inspections of the MCR chiller condensers with a frequency consistent with staff's recommended actions to manage loss of coating integrity. Therefore, the staff finds the applicant's proposed inspection frequency for these condensers acceptable.

- Circulating Water System Piping. Internal inspection of the coal tar coated circulating water system piping is currently being performed and will continue to be performed in the period of extended operation as part of Open-Cycle Cooling Water System 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 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 seventy-three 1-foot axial sections. As discussed above in the staff's evaluation of the RECW heat exchangers, the applicant has committed to perform subsequent inspections of the circulating water system piping with a frequency consistent with draft LR-ISG-2013-01 AMP XI.M42.

  The staff finds the applicant's proposed interval of inspections acceptable because conducting baseline inspections in the 10-year period prior to the period of extended operation, the scope of the inspections (i.e., seventy-three 1-foot axial sections), and the inspection intervals are consistent with the staff's recommended actions to manage loss of coating integrity.

- Cement-Lined Portions of the Fire Protection System Piping. The internal surfaces of the buried cement lined fire main header is currently being managed and will continue to be managed in the period of extended operation by the Fire Water System 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 period of extended operation as part of the Buried and Underground Piping and Tanks 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 period of extended operation. 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 (PIV) did not identify degradation of the cement lining. Within 10 years prior to the period of extended operation, 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. Opportunistic inspections of the cement lined pipe will continue to be performed during the period of extended operation as part of the Fire Water System program when normally inaccessible surfaces are made accessible due to required plant activities.

The staff noted that LRA Sections A.2.1.18 and B.2.1.18 state that, "[t]he 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." The staff finds the applicant's proposal to manage loss of the cement lining in the buried fire main header with the Fire Water System program acceptable because: (a) periodic header and fire hydrant flow tests are capable of detecting changes in flow resistance potentially indicative of cement lining debris buildup; (b) opportunistic inspections have not revealed any degradation of the cement lining; (c) opportunistic inspections will be performed during the period of extended operation; and (d) should localized cement lining degradation occur such that a through-wall hole occurs, the monitoring of operating pressure could detect the leak and corrective actions could be implemented prior to loss of the current licensing basis intended function(s) of the fire water system.

- <u>Emergency Diesel Generator Diesel Oil Storage Tanks</u>. Cleaning and internal inspection of the tanks is currently being performed and will continue to be performed in the period of extended operation as part of the Fuel Oil Chemistry 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 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 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. 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 staff noted that, given that the coatings installed on the internal surfaces of diesel fuel oil storage tanks are generally exposed to a static environment, the inspection interval may be conducted consistent with GALL Report AMP XI.M30 if no peeling, delamination, blisters, or rusting are observed during inspections, and cracking or flaking has been found acceptable, as documented in the staff's recommended actions to manage loss of coating integrity. Therefore there is a basis for conducting inspections of fuel oil storage tank coatings on the 10-year inspection frequency in the Fuel Oil Chemistry program in lieu of a 6-year interval. However, as stated above, "a small amount of surface rust staining was visible" during tank inspections and therefore, the emergency diesel generator diesel oil storage tank coatings do not meet the above criteria (e.g., no rusting). The staff recognizes that an area of minor coating damage that has been characterized as not being age-related and where physical inspections demonstrate that there is sound coating and satisfactory adhesion in the vicinity of the degradation may warrant the extended inspection frequencies of GALL Report AMP XI.30. However, the response to RAI 3.0.3-1 and the associated program changes did not discuss other critical considerations for allowing a longer inspection interval when small areas of degraded coatings is detected including: (a) demonstration that sufficient wall thickness is available to ensure that the current licensing basis function of the tank can be met; (b) alternative indications that leakage is occurring (e.g., level instrumentation); and (c) the factors to be used by the applicant to determine if loose coatings could transport. In addition, the response to RAI 3.0.3-1 stated that, "[t]he frequency of subsequent inspections will be established based on the baseline inspections." This statement appears to conflict with the specific inspection frequency specified in the Fuel Oil Chemistry program and the staff's recommended actions to manage loss of coating integrity. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (4) requesting that the applicant state the intent of the statement related to the subsequent inspection frequencies being determined based on the baseline inspection results; and, the basis for the periodicity of inspections for the emergency diesel generator diesel oil storage tank coatings if the prior inspection detected peeling, delamination, blisters, rusting, or unacceptable cracking and flaking.

In its response dated May 21, 2014, the applicant revised Commitment No. 20 to state that each fuel oil tank will be internally inspected 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. The wording, "[t]he frequency of subsequent inspections will be established based on the baseline inspections" was deleted. The applicant also stated that:

- o The current condition of the coating in the eight tanks is excellent with only minor mechanical damage (not age-related).
- o Preventive actions in the Fuel Oil Chemistry program mitigate the potential for loss of material (e.g., oil sampling, periodic draining of accumulated water and sediment).
- o The emergency diesel generator diesel oil storage tanks are equipped with level instrumentation and alarms that provide indication that leakage is occurring.
- o Should coating debris transport from the tank, the engine-driven and motor-driven fuel pump piping located downstream from the tanks are each equipped with basket strainers and duplex filters. The strainers and filters have differential pressure instrumentation and high differential pressure alarms. During the monthly run of each diesel, basket strainer differential pressure and duplex filter inlet and outlet pressures are recorded.
- o The acceptance criteria for coating degradation and requirements for physical inspections will be in accordance with program element 6 of draft LR-ISG-2013-01 AMP XI.M42. Commitment No. 20 was revised accordingly.

The staff noted that the acceptance criteria and physical inspection recommendations of draft LR-ISG-2013-01 AMP XI.M42 include:  (a) indications of peeling and delamination are not acceptable and the coatings are repaired or replaced, (b) blisters are evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in Regulatory Guide (RG) 1.54, "Service Level I, II, and III protective Coatings Applied to Nuclear Power Plants," (c) the cause of blisters needs to be determined if the blister is not repaired, (d) physical testing is conducted to ensure that a blister is completely surrounded by sound coating bonded to the surface, (e) if coatings are credited for corrosion prevention, the component's base material in the vicinity of a blister is inspected to determine if unanticipated corrosion has occurred, and (f) indications such as cracking, flaking, and rusting are to be evaluated by a coatings specialist qualified in accordance with an ASTM International standard endorsed in RG 1.54.

The staff finds the applicant's response and proposal to manage the coatings using the Fuel Oil Chemistry program acceptable because:  (a) plant-specific operating experience has demonstrated that only minor nonage-related coating damage has been noted to date, (b) only a small amount of surface rust staining was visible on the exposed carbon steel tank surface where the coating had been damaged and the applicant's program will include a requirement to inspect the tank's base material if the coating has been credited for corrosion prevention, (c) the tanks are equipped with level instrumentation and alarms that provide indication that leakage is occurring, and (d) basket strainer differential pressure and duplex filter inlet and outlet pressures are recorded during monthly diesel runs and these indications are capable of detecting potential coating debris.  In summary, there is reasonable assurance that the loss of material will not result in the tank inventory leaking to below minimum required levels based on the Fuel Oil Chemistry program preventive actions and indications and alarms available to the operators; and coating debris would be promptly detected based on the monthly diesel runs.  Additionally, the acceptance criteria and physical inspections of degraded coatings provide additional assurance that loss of material and coating debris would not impact the current licensing basis intended function(s) of the EDGs.  The staff's concern described in RAI 3.0.3.4-1 Part (4) is resolved.

- <u>RCIC Turbine Bearing Pedestals and HPCI Turbine Bearing Pedestals and Oil Reservoir</u>.  The RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir were originally coated internally with Rust-Ban ® paint.  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 pedestals and reservoir are managed by the Lubricating Oil Analysis program, which includes oil sampling and oil change activities that are capable of detecting coating degradation.  The oil sampling 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.  The 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.

The staff noted that the response to RAI 3.0.3-1 states that failure of the coatings could result in unanticipated or accelerated corrosion of the base metal and yet it also states that degraded coatings are removed and the uncoated substrate is not recoated. The response also states that the internal coatings are inspected on a refueling outage basis; however, it also states that the frequency of subsequent inspections will be established based on the baseline inspections. The response to 3.0.3-1 did not state an upper limit on the period of time prior to subsequent internal coating inspections, and the response did not incorporate this limit into the program, UFSAR supplement, and Commitment No. 27. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (5) requesting that the applicant state: (a) the basis for not recoating areas where the coating has been removed; and (b) the maximum interval to subsequent coating inspections and incorporate the inspection interval into the program, UFSAR supplement and Commitment No. 27.

In its response dated May 21, 2014, the applicant stated that the EPRI Terry Turbine Maintenance Guides for the RCIC and HPCI state to not attempt to repaint the surfaces of the oil reservoir or pedestals. The applicant clarified its response to RAI 3.0.3-1 that stated that 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. The clarification stated that unanticipated or accelerated corrosion could occur if the lubricating oil has been contaminated (e.g., from moisture intrusion); however, when contaminants are not present, lubricating oil systems do not suffer appreciable loss of material since the environment is not conducive to corrosion. The Lubricating Oil Analysis AMP provides for sampling, analysis, and condition monitoring for the identification of specific wear products and contamination in the lubricating oil environments. Oil sampling frequency for the HPCI and RCIC systems is every 91 days. These activities ensure that the oil environment in the oil reservoir and pedestals is maintained within acceptable limits to prevent or mitigate age-related degradation. Therefore coating is not necessary to mitigate aging effects. The applicant further stated that baseline inspections for the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir will occur in the 10-year period prior to the period of extended operation and the maximum interval of subsequent coating inspections will be consistent with draft LR-ISG-2013-01 AMP XI.M42 Table 4a. Commitment No. 27 was revised accordingly. The revised Commitment No. 27 also states that the acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with element 6 of draft LR-ISG-2013-01 GALL Report AMP XI.M42.

The staff noted that Technical Report 1007460, "Terry Turbine Maintenance Guide, RCIC Application EPRI," Section 19.2 states that turbine bearing pedestal degraded coatings should be removed and the surfaces not recoated. Likewise, Technical Report 1007459, "Terry Turbine Maintenance Guide, HPCI Application," Section 4.3 states that the oil reservoir should be inspected for flaking, blisters, and other signs of coating degradation and the surfaces not recoated and Section 19.2 states that for turbine bearing pedestals degraded coatings should be removed and the surfaces not recoated. The staff also noted that the EPRI documents were developed to provide improved maintenance practices that lead to improved turbine reliability.

The staff finds the applicant’s response and proposal to manage the coatings for the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir using the Lubricating Oil Analysis program acceptable because: (a) the staff’s review of EPRI Technical Reports 1007460 and 1007459 confirmed that it is not recommended that the RCIC turbine bearing pedestal and HPCI turbine bearing pedestal and turbine oil reservoir be recoated when degraded coatings are removed, (b) the RCIC and HPCI turbine oil is sampled frequently enough to detect potential degraded coatings, (c) conducting baseline inspections in the 10-year period prior to the period of extended operation, the subsequent inspection intervals, the acceptance criteria for coating degradation, and the requirements for physical inspections when degradation is identified are consistent with the staff’s recommended actions to manage loss of coating integrity, and (d) revising Commitment No. 27 is sufficient to ensure that the AMP implementing documents will be revised appropriately. The staff’s concern described in RAI 3.0.3.4-1 Part (5) is resolved.

_Training and Qualifications_. The applicant described specific training and qualification requirements as follows.

- Examiners currently performing coating assessment inspections of the emergency diesel generator diesel oil storage tanks and MCR chiller condensers are qualified to at least one of the following: (a) ASTM D 4537-91, “Standard Guide for Establishing Procedures To Qualify and Certify Personnel Performing Coating Work Inspection in Nuclear Facilities,” and American National Standards Institute (ANSI) N45.2.6-1978, to a minimum of level II, or (b) VT-3 to a minimum of Level II including documented orientation in performing coating surveillance. Additionally, examiners currently performing GL 89-13 program inspections of the MCR chiller condensers 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. As amended by letter dated May 21, 2014, the applicant revised LRA Sections A.2.1.12 and B.2.1.12, and Commitment No. 12 to require that the inspections of the MCR chiller condensers and circulating water system piping will be performed by inspectors qualified to international standards endorsed in Regulatory Guide (RG) 1.54, “Quality Assurance Requirements for Protective Coatings Applied to Water-Cooled Nuclear Power Plants,” including ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II. In addition, as amended by letter dated May 21, 2014, the applicant revised LRA Sections A.2.1.27 and B.2.1.27, and Commitment No. 27 to require that the inspections of the RCIC turbine bearing pedestals and HPCI turbine bearing pedestals and oil reservoir will be performed by inspectors qualified to international standards endorsed in RG 1.54, including, ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II.

  The staff noted that examiner qualifications meeting the recommendations in RG 1.54 are consistent with the staff’s recommended actions to manage loss of coating integrity. The staff finds the use of ASTM D 4537-91 and ANSI N45.2.6-1978 to qualify examiners acceptable because: (a) ASTM D 4537 is endorsed by RG 1.54, Revision 1; and (b) ANSI N45.2.6 certification is an acceptable basis for qualifying coatings inspectors based on RG 1.54, June 1973, Section C.1., which mandates conformance to the ANSI N45.2 quality assurance standards. The staff also noted that EPRI TR-1019157 contains material on coating nomenclature, inspections of surface preparation and coating application, typical degradation mechanisms, and review and analysis of inspection results.

In regard to using a visual examination (VT-3) Level II qualified examiner to conduct coating inspections, the staff noted that ASME Code Section XI, "Rules for Inservice Inspection of Nuclear Power Plant Components," Subarticle IWA-2300, "Qualification of Nondestructive Personnel," and ASTM D 4537 contain similar vision testing and educational requirements. However, given that VT-3 examinations are associated with determining the general mechanical and structural condition of components and their supports, providing a "documented orientation in performing coating surveillance" lacks sufficient specificity for the staff to conclude that the orientation is equivalent to ASTM D 4537 Section 9, "Examination." In addition, it is unclear to the staff whether a VT-3 Level II qualified examiner will have 3 or 6 months (depending on their education level) experience in coating inspection activities. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Request (6) requesting that the applicant: (a) provide a sufficient level of detail related to the orientation in performing coating surveillances provided to inspectors for the staff to independently conclude that the orientation is consistent with ASTM D 4537 Section 9; and (b) state whether VT-3 Level II qualified examiners will have 3 or 6 months (depending on their education level) experience in coating inspection activities.

In its response dated May 21, 2014, the applicant stated that, "VT-3 qualified examiners will not be used for either the baseline or periodic inspection of coatings. Individuals performing the inspection of coatings will be qualified to international standards endorsed in RG 1.54, including, ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II." The LRA program, UFSAR supplement, and associated Commitment Nos. 12, 20, 27 for the Open-Cycle Cooling Water System, Fuel Oil Chemistry, and Lubricating Oil Analysis programs have been revised accordingly.

The staff finds the applicant's response acceptable because VT-3 inspectors will not be used to conduct coating inspections for in-scope components. The staff's evaluation of the use of ASTM D 4537-91 and ANSI N45.2.6-1978 to qualify coatings inspectors is documented in the first section under *Training and Qualifications*, above. The staff's concern described in RAI 3.0.3.4-1 Request (6) is resolved.

- The applicant also stated that, in the event the initial inspection of the emergency diesel generator diesel oil storage tanks and MCR chiller condensers 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 and inspect coatings recoats, touchups, or repair activities. This level of qualification will continue through the period of extended operation for these inspections.

  The staff noted that the LRA program, UFSAR supplement, and associated Commitments Nos. 12, 20, 27 for the Open-Cycle Cooling Water System, Fuel Oil Chemistry, and Lubricating Oil Analysis programs contain similar wording. It is not clear to the staff why initial inspections that are not conducted by an ANSI N45.2.6 inspector would be credited as a baseline inspection. It is also not clear whether the statement "this level of qualification" refers to ANSI N45.2.6 qualified individuals or those without ANSI N45.2.6 qualifications.

  By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (7) requesting that the applicant: (a) for the Open-Cycle Cooling Water System, Fuel Oil Chemistry, and Lubricating Analysis programs, state the basis for why inspections conducted by individuals who do not have an ANSI N45.2.6 qualification should be credited as a baseline inspection; and (b) clarify the intent of the statement, “this level of qualification.”

In its response dated May 21, 2014, the applicant stated that, “[i]ndividuals performing the inspection of coatings will be qualified to international standards endorsed in RG 1.54, including, ASTM D 4537-91 and ANSI N45.2.6-1978 to a minimum of level II.” The LRA program, UFSAR supplement, and associated Commitments Nos. 12, 20, 27 for the Open-Cycle Cooling Water System, Fuel Oil Chemistry, and Lubricating Oil Analysis programs have been revised accordingly.

The staff finds the applicant’s response acceptable because personnel conducting baseline coating inspections will be qualified in accordance with standards endorsed in RG 1.54 or ANSI N45.2.6-1978. The staff’s evaluation of the use of ASTM D 4537-91 and ANSI N45.2.6-1978 to qualify coatings inspectors is documented in the first section under *Training and Qualifications*, above. The staff’s concern described in RAI 3.0.3.4-1 Part (7) is resolved.

- Examiners performing service water side inspections of the RECW heat exchangers are qualified to engineer certification guides, which include knowledge of EPRI TR-1019157 and a knowledge objective requirement to describe the inspection of coatings in heat exchangers. This level of qualification will continue through the period of extended operation. This is acceptable because the service water side of the RECW heat exchangers 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 due to flow blockage.

  The staff noted that, as amended, the Open-Cycle Cooling Water System program, UFSAR supplement, and associated Commitment No. 12 did not include a requirement for these inspectors to have knowledge of EPRI TR-1019157 and a knowledge objective requirement to describe the inspection of coatings in heat exchangers. Without these requirements being included in the program, it is unclear to the staff whether they will be incorporated into plant-specific training documents for the period of extended operation. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (8) requesting that the applicant amend LRA Sections A.2.1.12 and B.2.1.12, and Commitment No. 12, to state that these inspectors have knowledge of EPRI TR-1019157 and a knowledge objective requirement to describe the inspection of coatings in heat exchangers.

  In its response dated May 21, 2014, the applicant revised LRA Sections A.2.1.12 and B.2.1.12, and Commitment No. 12 to state that coating inspections of the RECW heat exchanger will be conducted by inspectors with a demonstrated working knowledge of EPRI Report 1019157.

  The staff finds the applicant’s response and the use of examiners with a demonstrated working knowledge of EPRI TR-1019157 to conduct inspections of the RECW heat exchangers acceptable because: (a) the GALL Report AMPs for programs inspecting the internal and external surfaces of other components in scope for 10 CFR 54.4(a)(2) spatial interaction only allow plant-specific qualifications for all inspections; (b) given that flow blockage is not an applicable aging effect, the purpose of the inspection is related to degradation of coatings that have exposed base metal, which is more easily detected than more minor indications of coating degradation, (c) the applicant’s response demonstrated that degraded coating conditions were detected by the examiners (see *RECW Heat Exchangers*, above); and (d) EPRI TR-1019157 contains sufficient information related to coatings and inspection parameters to appropriately orient inspectors to detect coating degradation related to exposure of base metal. The staff's concern described in RAI 3.0.3.4-1 Part (8) is resolved.

*Trending*. The applicant stated that the as-found condition of coatings 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.

The staff noted that the qualification level of the individual completing the inspection reports or completion remarks in the inspection work order was not stated. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (9) requesting that the applicant state the qualification level of the individual completing the inspection reports or completion remarks in the inspection work order.

In its response dated May 21, 2014, the applicant stated that, with the exception of inspections of the RECW heat exchangers, inspection reports will be prepared by individuals qualified to ASTM D 4537 and ANSI N45.2.6. Inspection results for the RECW heat exchangers will be documented in a heat exchanger report by the inspector.

The staff finds the applicant's response acceptable because, as documented above in *Training and Qualifications*, ASTM D 4537 and ANSI N45.2.6 are consistent with the staff's recommended actions to manage loss of coating integrity and RECW heat exchanger examinations will be conducted by inspectors with a demonstrated working knowledge of EPRI Report 1019157. The staff's concern described in RAI 3.0.3.4-1 Part (9) is resolved.

*Acceptance Criteria*. The applicant stated that 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 CAP for evaluation. As necessary, visual inspection may be supplemented by additional testing such as dry film thickness, adhesion, continuity, or other inspection technique as determined by the inspector to accurately assess coating condition.

The staff noted that the applicant did not state which precursors to coating failures would be considered not acceptable (e.g., peeling, delamination). The staff also noted that the applicant did not state the extent of blistering that would be found acceptable. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Part (10) requesting that the applicant state which precursors to coating failures would be considered not acceptable and the extent of blistering that would be found acceptable.

In its response dated May 21, 2014, the applicant stated the acceptance criteria for peeling, delamination, blistering, cracking, flaking, and rusting will be in accordance with draft LR-ISG-2013-01 AMP XI.M42 program element 6. Commitment Nos. 12, 20, and 27 were revised accordingly.

The staff noted that the RAI response did not include concrete-related aging mechanisms (e.g., spalling); however, Commitment No. 12 states, "[t]he acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014." The staff finds the applicant's response and acceptance criteria for the applicable programs acceptable because they are consistent with the staff's recommended actions to manage loss of coating integrity and concrete acceptance criteria is included in program element 6 of draft LR-ISG-2013-01 AMP XI.M42. The staff's concern described in RAI 3.0.3.4-1 Part (10) is resolved.

_Corrective Actions_. The applicant stated that currently the Site Coating Coordinator (not qualified in accordance with ASTM D 7108, "Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist") provides oversight of safety-related coating activities and evaluates coating deficiencies. As stated in Enhancement No. 1 and Commitment No. 37 of the Protective Coating Monitoring and Maintenance Program, the position of Nuclear Coatings Specialist will be created prior to the period of extended operation. This individual will be qualified to ASTM D 7108.

It is not clear to the staff whether an individual qualified to ASTM D 7108 will evaluate the results of the baseline coating inspections conducted prior to the period of extended operation. It is also not clear to the staff whether testing or examination will be conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating material. By letter dated April 24, 2014, the staff issued RAI 3.0.3.4-1 Request (11) requesting that the applicant state: (a) whether an individual qualified to ASTM D 7108 will evaluate the results of the baseline coating inspections conducted prior to the period of extended operation; and (b) whether testing or examination will be conducted to ensure that the extent of repaired or replaced coatings encompasses sound coating material.

In its response dated May 21, 2014, the applicant stated a coatings specialist qualified to ASTM D-7108 will evaluate baseline coating inspections conducted prior to the period of extended operation. Testing or examination (e.g., wet film thickness, dry film thickness, discontinuity, and adhesion) of repaired or replaced coating will be performed based on the type of coating system and type of repair. By letter dated June 4, 2014, the applicant amended LRA Sections A.2.1.12, A.2.1.20, and A.2.1.27 to state that the results of coating inspections will be evaluated by a coatings specialist qualified in accordance with ASTM D-7108.

The staff noted that the changes to Commitment Nos. 12, 20, and 27 to cite program element 6 of draft LR-ISG-2013-01 AMP XI.M42 for acceptance criteria provides sufficient guidance to encompass the testing and examination statements because the "acceptance criteria" program element of AMP XI.M42 includes recommendations associated with physical testing. The staff finds the applicant's response acceptable because appropriately qualified individuals will evaluate the results of coating inspections and because followup testing will be performed consistent with the staff's recommended actions to manage loss of coating integrity. The staff's concern described in RAI 3.0.3.4-1 Part (11) is resolved.

UFSAR Supplement. The staff reviewed the changes to the UFSAR supplement descriptions of the programs used to manage loss of coating integrity as amended by letters dated March 12, 2014, May 21, 2014, and June 4, 2014, and noted that it contains adequate detail to manage the licensing basis associated with loss of coating integrity. The staff also noted that the enhancements described above are reflected as changes to Commitment Nos. 12, 20, and 27.

Conclusion. On the basis of its review of the proposed changes to the Open-Cycle Cooling Water System, Fire Water System, Fuel Oil Chemistry, and Lubricating Oil Analysis programs as amended by letters dated March 14, 2014, May 21, 2014, and June 4, 2014, the staff determines that those program elements for which the applicant claimed consistency with the staff's guidance are consistent. In addition, the staff reviewed the exceptions and their justifications and determines that the AMPs, with the exceptions, are adequate to manage the applicable aging effects. Also, the staff reviewed the enhancements and confirmed that their implementation through Commitment No. 12, 18, 20, and 27 prior to the period of extended operation will make the AMPs adequate to manage the applicable aging effects. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3). The staff also reviewed the UFSAR supplements for these AMPs and concludes that they provide an adequate summary description of the program, as required by 10 CFR 54.21(d).

## 3.1 Aging Management of Reactor Coolant System

There are no changes or updates to this section of the SER.

## 3.2 Aging Management of Engineered Safety Features Section

3.2.2.3.3 High Pressure Coolant Injection System—Summary of Aging Management Review—LRA Table 3.2.2-3

Gray Cast Iron Tank (with Internal Coatings) Exposed to Lubricating Oil. As amended by letter dated March 14, 2014, in LRA Tables 3.2.2-3 and 3.2.2-4, the applicant stated that gray cast iron tanks (with internal coatings) exposed to lubricating oil will be managed for loss of coating integrity by the Lubricating Oil Analysis program. The AMR items cite generic note H.

The staff's evaluation of the acceptability of using the Lubricating Oil Analysis program to manage loss of coating integrity for the internal coatings of these tanks is documented in SSER Section 3.0.3.4.

On the basis of its review, the staff concludes for items in LRA Tables 3.2.2-3 and 3.2.2-4, that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.3.4 Reactor Core Isolation Cooling—Summary of Aging Management Review—LRA Table 3.2.2-4

The staff's evaluation for gray cast iron tanks (with internal coatings) exposed to lubricating oil, which will be managed for loss of coating integrity by the Lubricating Oil Analysis program and cite generic note H, is documented in SSER Section 3.2.2.3.3.

## 3.3 Aging Management of Auxiliary Systems

3.3.2.1.1 Loss of Material Due to General, Pitting, or Crevice Corrosion, and Cracking Due to Stress Corrosion Cracking

LRA Table 3.3.1, item 3.3.1-132 addresses insulated steel, stainless steel, copper-alloy, aluminum, or copper-alloy (greater than 15 percent zinc) piping, piping components, and tanks exposed to condensation or air-outdoor, which will be managed for loss of material due to corrosion and cracking due to stress-corrosion cracking (SCC). As amended by letter dated March 12, 2014, the applicant revised LRA Tables 3.3.2-16, 3.3.2-17, and 3.3.2-26 to state that insulated stainless steel piping and piping components exposed to indoor air environment will be managed for loss of material due to corrosion by the External Surfaces Monitoring of Mechanical Components program. The AMR items cite generic note A and include plant-specific notes 1 and 3, stating that the insulation for stainless steel components meets the requirements in NRC RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel." Based on this, the applicant claimed that the levels of leachable contaminants are controlled so that SCC is not promoted; therefore, loss of material is the only AERM for this material and environment.

The staff reviewed the applicant's claim that cracking was not an AERM. The staff noted that NRC RG 1.36 includes recommendations for qualification tests and chemical analyses to demonstrate that the ion concentrations of SCC-inducing leachable contaminants are within acceptable limits. The staff's review of the applicant's UFSAR did not identify instances of insulation with SCC-promoting leachable contaminants for the in-scope stainless steel piping. In addition, staff's review of OE during its onsite audit did not reveal any instances of SCC for in-scope insulated stainless steel piping at the applicant's facility. Based on the above, the staff finds the applicant's claim acceptable.

The staff concludes that for LRA item 3.3.1-132, associated with insulated stainless steel piping and piping components exposed to indoor environments, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.18.1 Loss of Material due to General, Pitting, Crevice, and Microbiologically Influenced Corrosion; and Fouling that Leads to Corrosion

LRA Table 3.3.1, item 3.3.1-64 addresses steel, copper-alloy piping, piping components, and piping elements exposed to raw water which will be managed for loss of material due to general, pitting, crevice, and microbiologically-influenced corrosion; and fouling that leads to corrosion. As amended by letter dated March 12, 2014, LRA Table 3.3.2-9 was revised to state that the internal surfaces of the backup fire water storage tank exposed to raw water would be managed for loss of material by the Aboveground Metallic Tanks program. This item cites generic note E. The staff's evaluation of the applicant's use of the Aboveground Metallic Tanks program to manage loss of material on the internal surfaces of the backup fire water storage tank is documented in SSER Section 3.0.3.3.3.

The staff finds the applicant's proposal to manage aging of the internal surfaces of the backup fire water storage tank using the Aboveground Metallic Tanks program acceptable because the program has been enhanced to include tests and inspections that are consistent with LR-ISG-2012-02 AMP XI.M27.

The staff concludes that for LRA item 3.3.1-64, as cited for the backup fire water storage tank, the applicant has demonstrated that the effects of aging for this component will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.1.18.2 Loss of Material Due to General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-89 addresses steel, copper-alloy piping, piping components, and piping elements exposed to moist air or condensation (internal) which will be managed for loss of material due to general, pitting, and crevice corrosion. As amended by letter dated March 12, 2014, LRA Table 3.3.2-9 was revised to state that the internal surfaces of the backup fire water storage tank exposed to air- or other gas–wetted (internal) would be managed for loss of material by the Aboveground Metallic Tanks program. This item cites generic note E. The staff's evaluation of the applicant's use of the Aboveground Metallic Tanks program to manage loss of material on the internal surfaces of the backup fire water storage tank is documented in SSER Section 3.0.3.3.3.

The staff finds the applicant's proposal to manage aging of the internal surfaces of the backup fire water storage tank using the Aboveground Metallic Tanks program acceptable because the program has been enhanced to include tests and inspections that are consistent with LR-ISG-2012-02 AMP XI.M27.

The staff concludes that for LRA item 3.3.1-89, as cited for the backup fire water storage tank, the applicant has demonstrated that the effects of aging for this component will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.3.8 Emergency Diesel Generator System—Summary of Aging Management Review—LRA Table 3.3.2-8

<u>Carbon Steel Tanks (with Internal Coatings) Exposed to Fuel Oil</u>. As amended by letter dated March 14, 2014, in LRA Table 3.3.2-8, the applicant stated that carbon steel tanks (with internal coatings) exposed to fuel oil will be managed for loss of coating integrity by the Fuel Oil Chemistry program. The AMR item cites generic note H.

The staff's evaluation of the acceptability of using the Fuel Oil Chemistry program to manage loss of coating integrity for the internal coatings of these tanks is documented in SSER Section 3.0.3.4.

On the basis of its review, the staff concludes for items in LRA Table 3.3.2-8, that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.9 Fire Protection System—Summary of Aging Management Review—LRA Table 3.3.2-9

<u>Cement Piping, Piping Components, and Piping Elements and Carbon Steel Tanks (with Internal Coatings) Exposed to Raw Water</u>. As amended by letter dated March 14, 2014, in LRA Table 3.3.2-9, the applicant stated that the cement piping, piping components, and piping elements and carbon steel tanks (with internal coating) exposed to raw water will be managed for loss of coating integrity by the Fire Water System and Aboveground Metallic Tanks programs, respectively. The AMR items cite generic note H. The staff noted that plant-specific note 11 clarifies that the piping is cement-lined versus being constructed from concrete.

The staff's evaluation of the acceptability of using the Fire Water System and Aboveground Metallic Tanks programs to manage loss of coating integrity for these components is documented in SSER Sections 3.0.3.3.3 and 3.0.3.4.

On the basis of its review, the staff concludes for items in LRA Table 3.3.2-9, that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.12 Nonsafety-Related Service Water System—Summary of Aging Management Review—LRA Table 3.3.2-12

<u>Carbon Steel Piping, Piping Components, Piping Elements, and Heat Exchangers (with Internal Coatings) Exposed to Raw Water</u>. As amended by letter dated March 14, 2014, in LRA Tables 3.3.2-12, 3.3.2-22, and 3.4.2-1, the applicant stated that carbon steel piping, piping components, piping elements, and heat exchangers (with internal coating) exposed to raw water will be managed for loss of coating integrity by the Open-Cycle Cooling Water System program. The AMR items cite generic note H.

The staff's evaluation of the acceptability of using the Open-Cycle Cooling Water System program to manage loss of coating integrity for these components is documented in SSER Section 3.0.3.4.

On the basis of its review, the staff concludes for items in LRA Tables 3.3.2-12, 3.3.2-22, and 3.4.2-1, that the applicant has appropriately evaluated the material and environment combinations not addressed in the GALL Report, and their intended function(s) will be maintained consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.3.22 Safety Related Service Water System —Summary of Aging Management Review—LRA Table 3.3.2-22

The staff's evaluation for carbon steel piping, piping components, and heat exchangers (with internal coating) exposed to raw water, which will be managed for loss of coating integrity by the Open-Cycle Cooling Water System program and cite generic note H, is documented in SSER Section 3.3.2.3.12

## 3.4 <u>Aging Management of Steam and Power Conversion Systems</u>

3.4.2.1.1 Loss of Material Due to General, Pitting, or Crevice Corrosion, and Cracking Due to Stress Corrosion Cracking

LRA Table 3.4.1, item 3.4.1-63 addresses insulated steel, stainless steel, copper-alloy, aluminum, or copper-alloy (greater than 15 percent zinc) piping, piping components, and tanks exposed to condensation or air-outdoor, which will be managed for loss of material due to corrosion and cracking due to SCC. As amended by letter dated March 12, 2014, the applicant revised LRA Tables 3.4.2-2 and 3.4.2-7 to state that insulated stainless steel piping and piping components exposed to indoor air environment will be managed for loss of material due to corrosion by the External Surfaces Monitoring of Mechanical Components program. The AMR items cite generic note A and include plant-specific notes 1 and 2, stating that the insulation for stainless steel components meets the requirements in NRC RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel." Based on this, the applicant claimed that the levels of leachable contaminants are controlled so that SCC is not promoted; therefore, loss of material is the only AERM for this material and environment.

The staff reviewed the applicant's claim that cracking is not an AERM. The staff noted that NRC RG 1.36 includes recommendations for qualification tests and chemical analyses to demonstrate that the ion concentrations of SCC-inducing leachable contaminants are within acceptable limits. The staff's review of the applicant's UFSAR did not identify instances of insulation with SCC-promoting leachable contaminants for the in-scope stainless steel piping. In addition, staff's review of OE during its onsite audit did not reveal any instances of SCC for in-scope insulated stainless steel piping at the applicant's facility. Based on the above, the staff finds the applicant's claim acceptable.

The staff concludes that for LRA item 3.4.1-63, associated with insulated stainless steel piping and piping components exposed to indoor environments, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

3.4.2.3.1 Circulating Water System —Summary of Aging Management Review—LRA Table 3.4.2-1

The staff's evaluation for carbon steel piping, piping components, and heat exchangers (with internal coating) exposed to raw water, which will be managed for loss of coating integrity by the Open-Cycle Cooling Water System program and cite generic note H, is documented in SSER Section 3.3.2.3.12.

## 3.5 Aging Management of Containments, Structures, and Component Supports

3.5.2.3.10 Piping and Component Insulation Commodity Group—Summary of Aging Management Evaluation

Calcium Silicate, Fiberglass, and Fiberglass Molded Insulation, and Insulation Jacketing Exposed to Air-Indoor Uncontrolled and Outdoor Air. By letter dated March 12, 2014, the applicant amended LRA Table 3.5.2-10 to state that calcium silicate, fiberglass, and fiberglass molded insulation, and insulation jacketing exposed to air-indoor uncontrolled and outdoor air will be managed for reduced thermal insulation resistance by the External Surfaces Monitoring of Mechanical Components program. These AMR items cite item 3.4.1-64 and generic note A. The amended table also states that cellular glass and ceramic fiber insulation, and insulation jacketing exposed to air-indoor uncontrolled and outdoor air will be managed for reduced thermal insulation resistance by the External Surfaces Monitoring of Mechanical Components program. These AMR items cite item 3.4.1-65 and generic note A.

The staff noted that LR-ISG-2012-02 added the two cited AMR items, 3.4.1-64 and 3.4.1-65, to address these material, environment, aging effect, and program combinations, and the staff confirmed the applicant's claim of consistency. The staff concludes that for LRA items 3.4.1-64 and 3.4.1-65, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended function(s) will be maintained consistent with the CLB for the period of extended operation as required by 10 CFR 54.21(a)(3).

Also, by letter dated March 12, 2014, the applicant amended LRA Table 3.5.2-10 to cite generic note F in lieu of generic note J for foamed plastic, Min-k, mineral fiber, and NUKON insulation, and insulation cement and finishing cement, and plastic mastic jacketing exposed to air-indoor uncontrolled and outdoor air, which will be managed for reduce thermal insulation resistance by the External Surfaces Monitoring of Mechanical Components program.

The staff's evaluation of the applicant's External Surfaces Monitoring of Mechanical Components program is documented in SER Section 3.0.3.1.15. The staff finds the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components program acceptable because, as amended by letter dated March 12, 2014, the program includes periodic inspections of either the bare metal surfaces under the insulation or the external surfaces of the insulation jacketing that are capable of detecting damage to the jacketing that would allow moisture penetration, which is consistent with the recommended approach in LR-ISG-2012-02.

## 3.6 Aging Management of Electrical and Instrumentation and Control Systems

There are no changes or updates to this section of the SER.

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# SECTION 4

# TIME LIMITED AGING ANALYSES

The staff does not have any changes or updates to this section of the safety evaluation report.

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# SECTION 5

# REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

The staff has provided the Advisory Committee on Reactor Safeguards with a copy of this supplemental safety evaluation report.

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# SECTION 6

# CONCLUSION

The staff concludes that the additional information provided by Exelon Generation Company, LLC, does not alter the conclusion proffered in the safety evaluation report issued in January 2013 and that the requirements of Title 10 of the *Code of Federal Regulations* section 54.29(a) have been met.

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# APPENDIX A

# LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

During the review of the Limerick Generating Station (LGS), Units 1 and 2 license renewal application by the staff of the U.S. Nuclear Regulatory Commission, Exelon Generation Company, LLC (Exelon), made commitments related to aging management programs to manage aging effects for structures and components.

The following table contains the final complete list of these commitments along with the implementation schedules and sources for each commitment.

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
|---|---|---|---|---|
| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 1 | Existing American Society of Mechanical Engineers (ASME) Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is credited. | A.2.1.1 | Ongoing | LRA |
| 2 | Existing Water Chemistry program is credited. | A.2.1.2 | Ongoing | LRA |
| 3 | Existing Reactor Head Closure Stud Bolting program is credited. | A.2.1.3 | Ongoing | LRA |
| 4 | Existing BWR Vessel ID Attachment Welds program is credited. | A.2.1.4 | Ongoing | LRA |
| 5 | Existing BWR Feedwater Nozzle program is credited. | A.2.1.5 | Ongoing | LRA |
| 6 | BWR Control Rod Drive Return Line Nozzle is an existing program that will be enhanced to:<br>1. Specify an extended volumetric inspection of the nozzle-to-cap weld to assure that the inspection includes base metal to a distance of one pipe wall thickness or 0.5 inches, whichever is greater, on both sides of the weld. | A.2.1.6 | Program to be enhanced before the period of extended operation | LRA |
| 7 | Existing BWR Stress Corrosion Cracking program is credited. | A.2.1.7 | Ongoing | LRA |
| 8 | Existing BWR Penetrations program is credited. | A.2.1.8 | Ongoing | LRA |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 9 | BWR Vessel Internals is an existing program that will be enhanced to:<br>1. Perform an assessment of the susceptibility of reactor vessel internal components fabricated from Cast Austenitic Stainless Steel (CASS) to loss of fracture toughness caused by thermal aging embrittlement. If material properties cannot be determined to perform the screening, they will be assumed susceptible to thermal aging for the purposes of determining program examination requirements.<br>2. Perform an assessment of the susceptibility of reactor vessel internal components fabricated from CASS to loss of fracture toughness caused by neutron irradiation embrittlement.<br>3. Specify the required periodic inspection of CASS components determined to be susceptible to loss of fracture toughness caused by thermal aging and neutron irradiation embrittlement. | A.2.1.9 | Program to be enhanced before the period of extended operation.<br>The initial inspections will be performed either before or within 5 years after entering the period of extended operation. | LRA |
| 10 | Existing Flow-Accelerated Corrosion program is credited. | A.2.1.10 | Ongoing | LRA |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 11 | Bolting Integrity is an existing program that will be enhanced to:<br>1. Provide guidance to ensure proper specification of bolting material, lubricant and sealants, storage, and installation torque or tension to prevent or mitigate degradation and failure of closure bolting for pressure retaining components.<br>2. Prohibit the use of lubricants containing molybdenum disulfide for closure bolting for pressure retaining components.<br>3. Minimize the use of high-strength bolting (actual measured yield strength equal to or greater than 150 ksi) for closure bolting for pressure retaining components. High-strength bolting, if used, will be monitored for cracking.<br>4. Perform visual inspection of bolting for the residual heat removal system, core spray system, high-pressure coolant injection system, and reactor core isolation cooling system suppression pool suction strainers for loss of material and loss of preload during each ISI inspection interval. | A.2.1.11 | Program to be enhanced before the period of extended operation | Letter dated March 12, 2012 |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 12 | Open-Cycle Cooling Water System is an existing program that will be enhanced to:<br>1. Perform internal inspection of buried safety-related service water (SW) piping when it is accessible during maintenance and repair activities.<br>2. Perform periodic inspections for loss of material in the nonsafety-related SW system at a minimum of five locations on each unit once every refueling cycle.<br>3. Replace the supply and return piping for the core spray pump compartment unit coolers.<br>4. Replace degraded RHRSW piping in the pipe tunnel.<br>5. Perform periodic inspections for loss of material in the safety-related SW system at a minimum of 10 locations every 2 years.<br>The open-cycle cooling water system aging management program also manages the loss of coating integrity in the SW side of the main control room chiller condensers and reactor enclosure cooling water heat exchangers, and, in circulating water system piping. | A.2.1.12 | Program to be enhanced before the period of extended operation<br>Inspection schedule as identified in the commitment | Letters dated February 15, and June 22, 2012, March 14, and May 21, 2014 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 12 (continued) | • As described below, baseline inspections will occur in the 10-year period prior to the period of extended operation. The maximum interval of subsequent coating inspections will comply with Table 4a of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014 (ADAMS Accession No. ML13262A442).<br>• 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.<br>• The inspection of the reactor enclosure cooling water heat exchangers will be performed by inspectors with a demonstrated working knowledge of EPRI Report 1019157, "Guideline on Nuclear Safety-Related Coatings."<br>• The inspection of seventy-three 1-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.<br>• The acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 13 | Closed Treated Water Systems is an existing program that will be enhanced to:<br>1. Perform condition monitoring and performance monitoring, including periodic testing and opportunistic and periodic NDE, to verify the effectiveness of water chemistry control to mitigate aging effects. A representative sample of piping and components will be selected based on likelihood of corrosion and inspected at an interval not to exceed once in 10 years during the period of extended operation.<br>2. Perform condition monitoring for the loss of material caused by cavitation erosion in the reactor enclosure cooling water piping to the 2A reactor water cleanup system (RWCU) nonregenerative heat exchanger. An initial inspection frequency of 4 years has been established. The inspection frequency will be re-evaluated and adjusted as necessary based on trend data. | A.2.1.13 | Program to be enhanced before the period of extended operation<br>Inspection schedule as identified in the commitment | Letter dated April 13, 2012 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 14 | Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems is an existing program that will be enhanced to:<br>1. Perform annual periodic inspections as defined in the appropriate ASME B30 series standard for all cranes, hoists, and equipment handling systems within the scope of license renewal. For handling systems that are infrequently in service, such as those only used during refueling outages, annual periodic inspections may be deferred until just before use.<br>2. Perform inspections of structural components and bolting for loss of material caused by corrosion, rails for loss of material caused by wear and corrosion, and bolted connections for loss of preload.<br>3. Evaluate loss of material caused by wear or corrosion and any loss of bolting preload on cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard.<br>4. Perform repairs to cranes, hoists, and equipment handling systems per the appropriate ASME B30 series standard. | A.2.1.14 | Program to be enhanced before the period of extended operation | LRA |
| 15 | Compressed Air Monitoring is an existing program that will be enhanced to:<br>1. Perform periodic analysis and trending of air quality monitoring results. | A.2.1.15 | Program to be enhanced before the period of extended operation | Letter dated February 15, 2012 |
| 16 | Existing BWR reactor water cleanup system is credited. | A.2.1.16 | Ongoing | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 17 | Fire Protection is an existing program that will be enhanced to:<br>1. Provide additional inspection guidance to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material.<br>2. Provide additional inspection guidance for identification of excessive loss of material caused by corrosion on the external surfaces of the halon and carbon dioxide systems. | A.2.1.17 | Program to be enhanced before the period of extended operation | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 18 | Fire Water System is an existing program that will be enhanced to:<br>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 before the 50-year inservice date and every 10 years thereafter.<br>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 before the period of extended operation and will be performed every 10 years thereafter.<br>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.<br>4. Inspect and clean the foam system water supply strainer after each system actuation and no less than once per refueling interval.<br>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.<br>6. Perform flow tests for the hydraulically most remote hose stations once every 5 years, scheduling the testing so that some of the tests are performed in each year of the 5-year interval. | A.2.1.18 | Program to be enhanced before the period of extended operation | Letters dated March 12, March 14, and May 21, 2014 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 18 (continued) | 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 10% at a specific location is entered into the corrective action program for evaluation.<br>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 2 years. | | | |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 18 (continued) | 9. Perform the following for fire water system sprinkler and deluge systems:<br>• Perform visual internal inspections, consistent with NFPA 25, for corrosion and obstructions to flow on at least five wet pipe sprinkler systems every 5 years.<br>• 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.<br>• 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.<br>• Perform visual internal inspections for corrosion and obstructions to flow for deluge systems of surfaces made accessible when deluge valves are serviced on at least 10 deluge systems on an interval no greater than 3 years. To provide reasonable assurance of the presence of sufficient coating, two of the ten inspections will be associated with the galvanized transformer deluge system piping.<br>• 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. | | | |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 18 (continued) | (9. continued)<br>• Perform an obstruction evaluation for conditions that indicate degraded flow.<br>• Perform followup volumetric inspections for pipe wall thickness if internal visual inspections detect surface irregularities that could be indicative of wall loss below nominal wall thickness.<br>• 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 5-year interval beginning 5 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% of the internal surface of piping segments that cannot be drained or piping segments that allow water to collect. In addition, in each 5-year interval of the period of extended operation, 20% 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. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 18 (continued) | 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. When these examinations identify pipe degradation, additional examinations will be performed in accordance with the following criteria:<br>• At least four additional locations will be examined if wall loss is greater than 50% of nominal wall thickness,<br>• Two additional locations will be examined if wall loss is 30% to 50% of nominal wall thickness and the calculated remaining life is less than 2 years,<br>• No additional examinations will be performed if wall loss is less than 30% of nominal wall thickness.<br>The Fire Water System aging management program also manages the loss of coating integrity in the buried cement lined fire main header.<br>• System flow testing activities measure system hydraulic resistance as a means of evaluating the internal piping condition.<br>• Opportunistic internal inspections evaluate the condition of the cement lined fire main header.<br>• Within 10 years prior to the period of extended operation, five internal visual inspections of the cement lining in the fire main header will be performed. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 19 | Aboveground Metallic Tanks is an existing program that will be enhanced to:<br>1. Include ultrasonic testing (UT) measurements of the bottom of the backup water storage tank. Tank bottom UT inspections will be performed within 5 years before entering the period of extended operation and every 5 years thereafter. If no tank bottom plate material loss is identified after the first two inspections, the remaining inspections will be performed whenever the tank is drained during the period of extended operation.<br>2. Provide visual inspections of the backup water storage tank external surfaces and include, on a sampling basis, removal of insulation to permit inspection of the tank surface. An inspection performed prior to entering the period of extended operation will include a minimum of 25 locations to demonstrate that the tank painted surface is not degraded under the insulation. Subsequent tank external surface visual inspection will be conducted on a 2-year frequency and include a minimum of four locations. Annual visual inspections will be performed of the tank insulation surface for degradation. Rips, tears, and gaps in the insulation skin will be repaired. Evidence of water intrusion beneath the insulation will be evaluated in accordance with the LGS corrective action program. | A.2.1.19 | Program to be enhanced before the period of extended operation<br>Inspection schedule as identified in the commitment | Letters dated February 15, 2012, March 12, 2014, and May 21, 2014 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 19 (continued) | 3. Perform visual inspections of the backup water storage tank wetted and nonwetted internal surfaces. Tank internal inspections will be performed within 5 years prior to entering the period of extended operation and every 5 years thereafter. The tank bottom will be inspected for evidence of voids beneath the floor in accordance with NFPA 25, Section 9.2.6.5. Where pitting and general corrosion to below the nominal wall thickness occurs or any coating failure occurs in which bare metal is exposed, additional inspections and tests shall be performed in accordance with NFPA 25, Section 9.2.7. These tests include adhesion testing of the coating in the vicinity of the coating failure, dry film thickness measurements, spot wet sponge testing, and nondestructive examination to determine remaining wall thickness where bare metal has been exposed. Tank bottom weld seams in the area of degraded coating will be leak tested in accordance with NFPA 25, Section 9.2.7, by vacuum-box testing or magnetic particle (MT) examination. In addition, adhesion testing shall be performed in the vicinity of blisters even though bare metal may not be exposed. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 20 | Fuel Oil Chemistry is an existing program that will be enhanced to:<br>1. Periodically drain water from the fire pump engine diesel oil day tank and the fire pump diesel engine fuel tank.<br>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 before 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 followup volumetric inspection.<br>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.<br>4. Perform periodic analysis for water and sediment and microbiological organisms for the diesel generator diesel oil storage tanks.<br>5. Perform periodic analysis for water and sediment content, total particulate concentration, and the levels of microbiological organisms for the diesel generator day tanks.<br>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. | A.2.1.20 | Program to be enhanced before the period of extended operation<br>Inspection schedule as described in the commitment | Letters dated March 14, 2014 and May 21, 2014 |

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| 20 (continued) | 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.<br>The Fuel Oil Chemistry aging management program also manages the loss of coating integrity in the eight main fuel oil storage tanks.<br>• Each fuel oil tank will be internally inspected 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<br>• 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<br>• The acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014. | | | |
| 21 | Existing Reactor Vessel Surveillance program is credited. | A.2.1.21 | Ongoing | LRA |
| 22 | One-Time Inspection is a new program that will be used to verify the system-wide effectiveness of the Water Chemistry, Fuel Oil Chemistry and Lubricating Oil Analysis programs. | A.2.1.22 | Program to be implemented before the period of extended operation.<br>One-time inspections will be performed within the 10 years before the period of extended operation. | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 23 | Selective Leaching is a new program that will include one-time inspections of a representative sample of susceptible components to determine if loss of material caused by selective leaching is occurring. | A.2.1.23 | Program to be implemented before the period of extended operation.<br>One-time inspections will be performed within the 5 years before the period of extended operation. | LRA |
| 24 | One-Time Inspection of ASME Code Class 1 Small-Bore Piping is a new program that will manage the aging effect of cracking in stainless steel and carbon steel Class 1 small-bore piping that is less than nominal pipe size (NPS) 4-inches, and greater than or equal to NPS 1-inch. | A.2.1.24 | Program to be implemented before the period of extended operation.<br>One-time inspections will be performed within the 6 years before the period of extended operation. | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 25 | External Surfaces Monitoring of Mechanical Components is a new program that manages aging effects of metallic and elastomeric materials through periodic visual inspection of external surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers<br><br>A sample of outdoor component surfaces that are insulated and a sample of indoor insulated components exposed to condensation (due to the in-scope component being operated below the dew point), are periodically inspected, under the insulation, every 10 years during the period of extended operation. Inspections subsequent to the initial inspection will consist of examination of the exterior surface of the insulation for indications of damage to the jacketing or protective outer layer of the insulation if the initial inspection verifies no loss of material beyond that which could have been present during initial construction. If the external visual inspections of the insulation reveal damage to the exterior surface of the insulation or if there is evidence of water intrusion through the insulation, then periodic inspections under insulation to detect corrosion under insulation will continue. | A.2.1.25 | Program to be implemented before the period of extended operation | Letter dated March 12, 2014 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 26 | Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is a new program that manages aging effects of metallic and elastomeric materials through visual inspections of internal surfaces for evidence of loss of material. Visual inspections are augmented by physical manipulation as necessary to detect hardening and loss of strength of elastomers.<br>This opportunistic approach is supplemented to ensure a representative sample of components within the scope of this program are inspected. At a minimum, in each 10-year period during the period of extended operation, a representative sample of 20% of the population (defined as components having the same combination of material, environment, and aging effect) or a maximum of 25 components per population is inspected. Where practical, the inspections focus on the bounding or lead components most susceptible to aging because of time in service, and severity of operating conditions. Opportunistic inspections continue in each 10-year period despite meeting the sampling minimum requirement. For the waste water environment, a maximum of 25 components per population will be inspected. To provide reasonable assurance of the presence of sufficient coating, 10 of the 25 internal inspections will be of the normal waste, oily waste, sanitary waste and storm drain galvanized piping, and 15 of the internal inspections will be of the radioactive floor and equipment drain carbon steel piping. | A.2.1.26 | Program to be implemented before the period of extended operation | Letters dated March 12, 2014 and May 21, 2014 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 27 | Existing Lubricating Oil Analysis program is credited.<br>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.<br>• As described below, baseline inspections will occur in the 10-year period prior to the period of extended operation. The maximum interval of subsequent coating inspections will comply with Table 4a of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014 (ADAMS Accession No. ML13262A442).<br>• 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.<br>• The acceptance criteria for coating degradation and the requirements for physical inspections when degradation is identified will be in accordance with Element 6 of GALL Report AMP XI.M42 in draft LR-ISG-2013-01 dated January 6, 2014. | A.2.1.27 | Ongoing | Letters dated March 14, 2014 and May 21, 2014 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 28 | Monitoring of Neutron-Absorbing Materials Other than Boraflex is an existing program that will be enhanced to:<br>1. Perform test coupon analysis on a 10-year frequency, beginning no earlier than 2020 for Unit 1 and 2021 for Unit 2.<br>2. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded before the next scheduled test coupon analysis.<br>3. Resume the accelerated exposure configuration for the Boral coupons (surrounded by freshly discharged fuel assemblies) at each of five additional refueling cycles, beginning with the next refueling for each unit (2013 for Unit 2, 2014 for Unit 1).<br>4. Maintain the coupon exposure such that it is bounding for the Boral material in all spent fuel racks, by relocating the coupon tree to a different spent fuel rack cell location each cycle and by surrounding the coupons with a greater number of freshly discharged fuel assemblies than that of any other cell location. | A.2.1.28 | Program to be enhanced before the period of extended operation.<br>Inspection schedule as described in the commitment. | Letters dated February 28, 2012 and April 27, 2012 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 29 | Buried and Underground Piping and Tanks is an existing program that will be enhanced to:<br>1. If adverse indications are detected during inspection of in-scope buried piping, inspection sample sizes within the affected piping categories are doubled. If adverse indications are found in the expanded sample, an analysis is conducted to determine the extent of condition and extent of cause. The size of the follow-on inspections will be determined based on the extent of condition and extent of cause.<br>2. Coat the underground emergency diesel generator (EDG) system fuel oil piping before the period of extended operation. The coating will be in accordance with Table 1 of National Association of Corrosion Engineers (NACE) SP0169-2007 or Section 3.4 of NACE RP0285-2002. | A.2.1.29 | Program to be enhanced before the period of extended operation<br>Inspection schedule as described in the commitment | Letters dated February 15, 2012, March 30, 2012, and June 17, 2013 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 29 (continued) | 3. Perform direct visual inspections and volumetric inspections of the underground Emergency Diesel Generator System fuel oil piping and components during each 10-year period beginning 10 years prior to the entry into the period of extended operation. Prior to the period of extended operation all in scope Emergency Diesel Generator System fuel oil piping and components located in underground vaults will undergo a 100 percent visual inspection. Volumetric inspections will also be performed. After entering the period of extended operation, 2 percent of the linear length of in scope Emergency Diesel Generator System fuel oil piping and components located in underground vaults will undergo direct visual inspections and volumetric inspections every 10 years. Inspection locations after entering the period of extended operation will be selected based on susceptibility to degradation and consequences of failure. Visual inspections will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 29 (continued) | 4. Perform two sets of volumetric inspections of the safety-related SW system underground piping and components during each 10-year period beginning 10 years before the entry into the period of extended operation. Each set of volumetric inspections will assess either the entire length of a run of in-scope safety-related SW system piping and components in the underground vault or a minimum of 10 feet of the linear length of in-scope safety-related SW system piping and components in the underground vault. Inspection locations will be selected based on susceptibility to degradation and consequences of failure.<br>5. Specify that visual inspections of safety-related SW system underground piping and components will be performed by a NACE Coating Inspector Program Level 2 or 3 qualified inspector or an individual that has attended the EPRI Comprehensive Coatings Course and completed the EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course.<br>6. Perform trending of the cathodic protection testing results to identify changes in the effectiveness of the system and to ensure that the rectifiers remain operational at least 85% of the time, and cathodic protection effectiveness will be maintained >80%. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 29 (continued) | 7. Modify the yearly cathodic protection survey acceptance criterion to meet NACE SP0169-2007 standards and add a statement that if negative polarized potential exceeds −1100mV relative to copper/copper sulfate electrode an issue report will be entered into the corrective action program. In performing cathodic protection surveys, only the −850mV polarized potential criterion for steel piping will be used for acceptance criteria and determination of cathodic protection system effectiveness, unless the −100mV polarization criterion can be demonstrated effective through use of buried coupons, electrical resistance probes, or placement of reference cells in the immediate vicinity of the piping being measured.<br>8. Whenever pipe is excavated and damage to the coating is significant and the damage was caused by nonconforming backfill, an extent of condition evaluation should be conducted to ensure that the as-left condition of backfill in the vicinity of observed damage will not lead to further degradation. | | | |
| 30 | ASME Section XI, Subsection IWE is an existing program that will be enhanced to:<br>1. Manage the suppression pool liner and coating system to:<br>a. Remove any accumulated sludge in the suppression pool every refueling outage.<br>b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period. | A.2.1.30 | Program to be enhanced before the period of extended operation<br>Inspection schedule as described in the commitment | Letter dated October 25, 2012 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 30 (continued) | c. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following prior to the period of extended operation:<br>• Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.<br>• Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated based on ranking of affected surface area, high to low. This plate thickness loss criterion for local areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.<br>• For plates with greater than 25 percent coating depletion, the affected area will be recoated based on ranking of affected surface area depleted and metal thickness loss. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 30 (continued) | d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the period of extended operation:<br>• Local areas (less than 2.5 inches in diameter) of general corrosion that are greater than 50 mils plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for local areas will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.<br>• Areas of general corrosion greater than 25 mils average plate thickness loss will be recoated in the outage they are identified. This plate thickness loss criterion for areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.<br>• For plates with greater than 25% coating depletion, the affected area will be recoated no later than the next scheduled inspection. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 30 (continued) | The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss.<br>2. Use the results of the ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:<br>• Local areas (less than or equal to 5.5 inches in any direction) that have 40 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for local areas will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.<br>• Areas of general corrosion (greater than 5.5 inches in any direction) that have 30 mils or more metal thickness loss will be recoated. This downcomer metal thickness loss criteria for areas of general corrosion will also be used to determine when the submerged portions of the downcomers require augmented inspection in accordance with ASME Section XI, Subsection IWE, Category E-C.<br>3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 30 (continued) | 4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. | | | |
| 31 | ASME Section XI, Subsection IWL is an existing program that will be enhanced to:<br>1. Include second-tier acceptance criteria of ACI 349.3R. | A.2.1.31 | Program to be enhanced before the period of extended operation | LRA |
| 32 | ASME Section XI, Subsection IWF is an existing program that will be enhanced to:<br>1. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. | A.2.1.32 | Program to be enhanced before the period of extended operation | LRA |
| 33 | Existing 10 CFR Part 50, Appendix J program is credited. | A.2.1.33 | Ongoing | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 34 | Masonry Walls is an existing program that will be enhanced to:<br>1. Add the following structures with masonry walls to the program scope:<br>a. administration building warehouse<br>b. fuel oil pumphouse<br>c. transformer foundation dike walls<br>2. Provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and walls that could impact the wall's intended function.<br>3. Require an inspection frequency of not greater than 5 years.<br>4. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R. | A.2.1.34 | Program to be enhanced before the period of extended operation<br>Inspection schedule as described in the commitment | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 35 | Structures Monitoring is an existing program that will be enhanced to:<br><br>1. Add the following structures:<br><br>a. admin building warehouse<br>b. fuel oil pumphouse<br>c. SW pipe tunnel<br>d. yard structures<br><br>• aux fire water storage tank foundation<br>• backup fire pump house and foundation<br>• well pump #3 enclosure and foundation<br>• railroad bridge<br>• manholes 001 and 002<br>• fuel oil storage tank dike<br>• transformer foundations and dikes | A.2.1.35 | Program to be enhanced before the period of extended operation<br><br>Inspection schedule as described in the commitment | Letter dated April 13, 2012 |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 35 (continued) | 2. Add the following components and commodities:<br>a. pipe, electrical, and equipment component support members<br>b. pipe whip restraints and jet impingement shields<br>c. panels, racks, and other enclosures<br>d. sliding surfaces<br>e. sump and pool liners<br>f. electrical cable trays and conduits<br>g. electrical duct banks<br>h. tube tracks<br>i. doors<br>j. penetration seals<br>k. blowout panels<br>l. permanent drywell shielding<br>m. roof scuppers | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 35 (continued) | 3. Monitor groundwater chemistry on a frequency not to exceed 5 years for pH, chlorides, and sulfates and verify that it remains nonaggressive, or evaluate results exceeding criteria to assess impact, if any, on below-grade concrete.<br><br>4. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high-strength bolts to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0.<br><br>5. Monitor concrete for areas of abrasion, erosion, and cavitation degradation, drummy areas that can exceed the cover concrete thickness in depth, popouts and voids, scaling, and passive settlements or deflections.<br><br>6. Perform inspections on a frequency not to exceed 5 years.<br><br>7. Perform inspections of subdrainage sump pit internal concrete on a 5-year frequency as a leading indicator the condition of below grade concrete exposed to ground water.<br><br>8. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 35 (continued) | 9. Perform inspection of elastomeric vibration isolation elements and structural seals for cracking, loss of material and hardening. Visual inspections of elastomeric vibration isolation elements are to be supplemented by manipulation to detect hardening when vibration isolation function is suspect.<br><br>10. Monitor accessible sliding surfaces to detect significant loss of material caused by wear, corrosion, debris, or dirt, which could result in lockup or reduced movement.<br><br>11. Perform opportunistic inspection of below grade portions of in-scope structures in the event of excavation that exposes normally inaccessible below grade concrete.<br><br>12. Include applicable acceptance criteria from ACI 349.3R.<br><br>13. Clarify that loose bolts and nuts and cracked high-strength bolts are not acceptable unless accepted by engineering evaluations. | | | |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 36 | RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants is an existing program that will be enhanced to:<br>1. Require inspection of structural bolting integrity (loss of material and loosening of the bolts).<br>2. Require monitoring of aging effects for increase of porosity and permeability of concrete structures and loss of material for steel components.<br>3. Require the proper functioning of dike drainage systems.<br>4. Require increased inspection frequency if the extent of the degradation is such that the structure or component may not meet its design basis if allowed to continue uncorrected until the next normally scheduled inspection.<br>5. Require (a) evaluation of the acceptability of inaccessible areas when conditions exist in the accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, and (b) examination of the exposed portions of the below-grade concrete when excavated for any reason.<br>6. Monitor raw water chemistry at least once every 5 years for pH, chlorides, and sulfates and verify that it remains nonaggressive, or evaluate results exceeding criteria to assess impact, if any, on submerged concrete. | A.2.1.36 | Program to be enhanced before the period of extended operation<br>Inspection schedule as described in the commitment | LRA |

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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 36 (continued) | 7. Require visual examinations of the Spray Pond and Pumphouse submerged wetwell concrete for signs of degradation during maintenance activities. If significant concrete degradation is identified, a plant-specific AMP should be implemented to manage the concrete aging during the period of extended operation.<br>8. Require that active cracks in structural concrete or extent of corrosion in steel are documented and trended, until the condition is no longer occurring or until a corrective action is implemented.<br>9. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R.<br>10. Provide guidance for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. Revise storage requirements for high-strength bolts to include recommendations of Research Council on Structural Connections (RCSC) Specification for Structural Joints Using High Strength Bolts, Section 2.0. | | | |
| 37 | Protective Coating Monitoring and Maintenance Program is an existing program that will be enhanced to:<br>1. Create the position of Nuclear Coatings Specialist qualified to ASTM D 7108 standards. | A.2.1.37 | Program to be enhanced before the period of extended operation | LRA |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 38 | Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage aging of the insulation material for non-EQ cables and connections. Accessible cables and connections located in adverse localized environments will be visually inspected at least once every 10 years for indications of reduced insulation resistance, such as embrittlement, discoloration, cracking, melting, swelling, or surface contamination. | A.2.1.38 | Program and initial inspections to be implemented before the period of extended operation<br>Inspection schedule as described in the commitment | LRA |
| 39 | Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits is a new program that will be used to manage aging of non-EQ cable and connection insulation of the in-scope portions of the process radiation monitoring and neutron monitoring systems.<br>Calibration and cable tests will be performed and results will be assessed for reduced insulation resistance before the period of extended operation and at least once every 10 years during the period of extended operation. | A.2.1.39 | Program and initial assessment of calibration and test results to be implemented before the period of extended operation<br>Assessment schedule identified in commitment | LRA |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 40 | Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements is a new program that will be used to manage the aging effects and mechanisms of non-EQ, in-scope, inaccessible power cables.<br>Cables will be tested using a proven test for detecting reduced insulation resistance of the cable's insulation system. The cables will be tested at least once every 6 years. More frequent testing may occur based on test results and operating experience (OE).<br>Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this AMP will be inspected for water collection with subsequent corrective actions (e.g., water removal), as necessary. Before the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific OE with cable wetting or submergence, including water accumulation over time and event driven occurrences such as heavy rain or flooding. Operation of dewatering devices will be confirmed before any known or predicted heavy rain or flooding event. During the period of extended operation, the inspections will occur at least annually. | A.2.1.40 | Program and initial tests and inspections to be implemented before the period of extended operation<br>Test and Inspection schedule identified in commitment | Letter dated February 28, 2012 |
| 41 | Metal Enclosed Bus is a new program that will be used to manage aging of in-scope metal enclosed bus. The internal portions of bus enclosure assemblies, bus insulation, bus insulating supports and elastomers will be visually inspected. A sample (20% with a maximum sample size of 25) of the accessible metal enclosed bus bolted connection population will be tested using thermography.<br>The inspections and thermography will be performed at least once every 10 years for indications of aging degradation. | A.2.1.41 | Program and initial tests and inspections to be implemented before the period of extended operation<br>Test and inspection schedule identified in commitment | LRA |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 42 | Fuse Holders AMP is a new program that applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects.<br>Fuse holders subject to increased resistance of connection or fatigue, will be tested, by a proven test methodology, at least once every 10 years for indications of aging degradation. Visual inspection is not part of this program. | A.2.1.42 | Program and initial tests to be implemented before the period of extended operation<br>Test schedule identified in commitment | LRA |
| 43 | Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that will implement one-time testing of a representative sample (20 percent with a maximum sample size of 25) of non-EQ electrical cable connections to ensure that either aging of metallic cable connections is not occurring or that the existing preventive maintenance program is effective such that a periodic inspection program is not required. | A.2.1.43 | Program and one-time tests to be implemented before the period of extended operation | LRA |
| 44 | Fatigue Monitoring is an existing program that will be enhanced to:<br>1. Monitor additional plant transients that are significant contributors to fatigue usage and to impose administrative transient cycle limits corresponding to the limiting numbers of cycles used in the environmental fatigue calculations. | A.3.1.1 | Program to be enhanced before the period of extended operation | LRA |
| 45 | Existing Environmental Qualification (EQ) of Electric Components program is credited. | A.3.1.2 | Ongoing | LRA |

| APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS | | | | |
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| **Item** | **Commitment** | **UFSAR Supplement Section/ LRA Section** | **Enhancement or Implementation Schedule** | **Source** |
| 46 | The OE program is an existing program that will be enhanced to:<br>1. Explicitly require the review of OE for aging-related degradation.<br>2. Establish criteria to define aging-related degradation.<br>3. Establish identification coding for use in identification, trending, and communications of aging-related degradation.<br>4. Require communication of significant internal aging-related degradation, associated with system, structures, and components in the scope of license renewal, to other Exelon plants and to the industry. Criteria will be established for determining when aging-related degradation is significant.<br>5. Require review of external OE for information related to aging management, and evaluation of such information for potential improvements to LGS aging management activities.<br>6. Provide training to those responsible for screening, evaluating and communicating OE items related to aging management. | A.1.6 | Program to be enhanced no later than the date that the renewed operating licenses are issued | Letters dated March 13, July 11, September 12, and October 12, 2012 |
| 47 | Re-evaluate the flaw in the Unit 1 RPV nozzle to safe-end weld VRR-1RD-1A-N2H in accordance with ASME Section XI, subsection IWB-3600 for the 60-year service period corresponding to the LR term. | Appendix C | Before the period of extended operation | Letter dated February 15, 2012 |

# APPENDIX B

# CHRONOLOGY

This appendix lists chronologically the routine licensing correspondence between the staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) and Exelon Generation Company, LLC (Exelon). This appendix updates the correspondence regarding the staff's review of the Limerick Generating Station (LGS) license renewal application (LRA) (under Docket Nos. 50-352 and 50-353) since the issuance of the Final safety evaluation report (SER) in January 2013.

| **APPENDIX B: CHRONOLOGY** | |
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| **Date** | **Subject** |
| 2/14/2013 | Letter from Stetkar J., ACRS, to Macfarlane A., Chairman NRC, "Report on the Safety Aspects of the License Renewal Application for the Limerick Generating Station," (ADAMS Accession No. ML13058A150) |
| 2/21/2013 | Letter from Gallagher M., Exelon Generation Co., LLC, to U.S. NRC Document Control Desk, "Review of the Safety Evaluation Report related to the Limerick Generating Station License Renewal Application," (ADAMS Accession No. ML13053A374) |
| 6/17/2013 | Letter from Gallagher M., Exelon Generation Co., LLC, to U.S. NRC Document Control Desk, "10 CFR 54.21(b) Annual Amendment to the Limerick Generating Station License Renewal Application and Review of Interim Staff Guidance," (ADAMS Accession No. ML13168A432) |
| 8/1/2013 | Letter from Plasse R., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Request for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555 AND ME6556)," (ADAMS Accession No. ML13204A112) |
| 8/16/2013 | Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Response to NRC Request for Additional Information, dated August 1, 2013, Related to Limerick Generating Station License Renewal Application," (ADAMS Accession No. ML13228A308) |
| 9/5/2013 | Meeting Summary from Plasse R., U.S. NRC, "Summary of Telephone Conference Call held on July 16, 2013, between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Requests for Additional Information Pertaining to the Limerick Generating Station License Renewal," (ADAMS Accession No. ML13238A316) |
| 9/25/2013 | Letter from Gallagher M., Exelon Generation Co., LLC, to U.S. NRC Document Control Desk, "Review of Interim Staff Guidance LR-ISG-2012-01, Wall Thinning Due to Erosion Mechanisms," (ADAMS Accession No. ML13268A353) |

| APPENDIX B: CHRONOLOGY | |
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| **Date** | **Subject** |
| 2/10/2014 | Letter from Plasse R., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, “Request for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555 AND ME6556),” (ADAMS Accession No. ML14034A060) |
| 3/12/2014 | Letter from Gallagher M., Exelon Generation Co., LLC, to U.S. 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,” (ADAMS Accession No. ML14034A376) |
| 3/14/2014 | Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, “Response to NRC Request for Additional Information, dated February 10, 2014, Related to Limerick Generating Station License Renewal Application,” (ADAMS Accession No. ML14071A378) |
| 4/24/2014 | Letter from Plasse R., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, “Request for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555 AND ME6556),” (ADAMS Accession No. ML14107A212) |
| 5/21/2014 | Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, “Response to NRC Request for Additional Information, dated April 24, 2014, and Minor Changes to the LRA Supplement dated March 12, 2014, Related to Limerick Generating Station License Renewal Application,” (ADAMS Accession No. ML14142A172) |
| 6/4/2014 | Letter from Gallagher M., Exelon Generation Co., LLC, to U.S. NRC Document Control Desk, “10 CFR 54.21(b) Annual Amendment to the Limerick Generating Station License Renewal Application and Revision to UFSAR Supplement Related to the Response to RAI 3.0.3.4-1,” (ADAMS Accession No. ML14155A144) |

# APPENDIX C

# PRINCIPAL CONTRIBUTORS

This appendix lists the principal contributors for the development of this supplemental safety evaluation report and their areas of responsibility.

| APPENDIX C: PRINCIPAL CONTRIBUTORS | |
|---|---|
| **Name** | **Responsibility** |
| Y. Diaz-Sanabria | Management Oversight |
| J. Gavula | Reviewer-Mechanical |
| W. Holston | Reviewer-Mechanical |
| R. Kalikian | Reviewer-Mechanical |
| D. Morey | Management Oversight |
| R. Plasse | Project Manager |
| C. Ng | Project Manager |
| J. Wise | Reviewer-Mechanical |

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# APPENDIX D

# REFERENCES

This appendix lists the references used throughout this supplemental safety evaluation report for review of the license renewal application (LRA) for Limerick Generating Station.



| APPENDIX D: REFERENCES |
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| **NRC Documents** |
| GL 89-13, "Service Water System Problems Affecting Safety-Related Equipment," July 1989. |
| NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," Revision 2, December 2010. |
| NUREG-1801, "Generic Aging Lessons Learned (GALL) Report," Revision 2, December 2010. |
| RG 1.54, "Service Level I, II, and III Protective Coatings Applied To Nuclear Power Plants." |
| **Regulations** |
| *U.S. Code of Federal Regulations* (CFR), "Domestic Licensing of Production and Utilization Facilities," Part 50, Title 10, "Energy," Office of the Federal Register, National Archives and Records Administration, 2012. |
| 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," (2012). |
| **Industry Documents** |
| US Department of Transportation, Federal Highway Administration, Publication No. FHWA-NHI-00-044, "Corrosion/Degradation of Soil Reinforcements for Mechanically Stabilized Walls and Reinforced Soil Slopes," September 2000. |
| Electric Power Research Institute (EPRI) Nuclear Safety Analysis Center (NSAC)-202L-R3, "Recommendations for an Effective Flow-Accelerated Corrosion Program." Nonproprietary version, August 2007. |
| EPRI Comprehensive Coatings Course. |
| EPRI Buried Pipe Condition Assessment and Repair Training Computer Based Training Course. |
| EPRI Technical Report 1007460, "Terry Turbine Maintenance Guide, RCIC Application," September, 2012. |
| EPRI Technical Report 1007459, "Terry Turbine Maintenance Guide, HPCI Application," November, 2012. |

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| EPRI TR-1019157, “Guideline on Nuclear Safety-Related Coatings,” Revision 2. |
| American National Standards Institute (ANSI) N45.2.6-1978. |
| NEI 95-10, “Industry Guideline for Implementing the Requirements of 10 CFR Part 54–The License Renewal Rule,” Revision 6, June 2005. |
| **Industry Codes and Standards** |
| American Society of Mechanical Engineers (ASME) Code Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” Subarticle IWA-2300, “Qualification of Nondestructive Personnel, 2007 Edition with 2008 Addenda. |
| ASME Code, Section XI, “Rules for Inservice Inspection of Nuclear Power Plant Components,” 2007 Edition with 2008 Addenda. |
| ASME Code Case N-513, “Evaluation Criteria for Temporary Acceptance of Flaws in Moderate Energy Class 2 or 3 Piping,” January 26, 2009. |
| National Association of Corrosion Engineers (NACE), Peabody’s Control of Pipeline Corrosion, Second Edition, 2001. |
| ASTM D 4537-91, “Standard Guide for Establishing Procedures To Qualify and Certify Personnel Performing Coating Work Inspection in Nuclear Facilities. |
| ASTM D5163-08, “Standard Guide for Establishing a Program for Condition Assessment of Coating Service Level I Coating Systems in Nuclear Power Plants,” 2008. |
| ASTM D7108-05, ‘Standard Guide for Establishing Qualifications for a Nuclear Coatings Specialist” |
| ASTM D448-08, “Standard Classification for Sizes of Aggregate for Road and Bridge Construction” |
| ASTM D7167-05, “Standard Guide for Establishing Procedures to Monitor the Performance of Safety-Related Coating Service Level III Lining Systems in an Operating Nuclear Power Plant” |
| National Association of Corrosion Engineers (NACE) International SP0169-2007, “Control of External Corrosion on Underground or Submerged Metallic Piping Systems,” NACE International, Houston, TX, March 2007. |
| National Fire Protection Association (NFPA) 25, “Standard for Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” NFPA, Quincy, MA, 2008. |
| National Fire Protection Association (NFPA) 25, “Standard for Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems,” NFPA, Quincy, MA, 2011. |