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

January 10, 2013

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

SUBJECT: 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 Generation Company, LLC submitted an application to the U.S. Nuclear Regulatory Commission (NRC) requesting the renewal of the facility operating licenses for the Limerick Generating Station, Units 1 and 2 (Limerick) for up to an additional 20 years beyond the current licenses' expiration dates. The license renewal application (LRA) was submitted pursuant to Title 10 of the *Code of Federal Regulations* Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The staff determined that the LRA was complete and acceptable for docketing on August 12, 2011.

With regards to the application, the NRC staff has reviewed the Limerick LRA, performed site audits and inspections, issued requests for additional information (RAIs), reviewed your responses to the staff's RAIs and developed a safety evaluation report (SER) with open items dated July 30, 2012, and reviewed your comments on this SER. On the basis of its review of your response to the open items and other comments, the NRC staff has developed the enclosed SER to document its findings associated with the safety review of the LRA and supporting documentation for Limerick.

If you have any questions regarding this matter, please contact the license renewal project manager, Mr. Patrick Milano, by telephone at (301) 415-1457 or by email at Partick.Milano@nrc.gov.

Sincerely,

Melanie A. Galloway

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

Docket Nos. 50-352 and 50-353

Enclosure:
As stated

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Letter to M. Gallagher from John Lubinski dated January 10, 2013

SUBJECT: SAFETY EVALUATION REPORT RELATED TO THE LICENSE RENEWAL OF LIMERICK GENERATING STATION, UNITS 1 AND 2 (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

Docket Nos. 50-352 and 50-353

Exelon Generation Company, LLC

United States Nuclear Regulatory Commission

Office of Nuclear Reactor Regulation

January 2013

ABSTRACT

This safety evaluation report (SER) documents the technical review of the Limerick Generating Station (LGS), Units 1 and 2, license renewal application (LRA) by the United States Nuclear Regulatory Commission (NRC) staff (the staff). By letter dated June 22, 2011, Exelon Generation Company, LLC submitted the LRA in accordance with Title 10 of the *Code of Federal Regulations* Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." Exelon requests renewal of the LGS Units 1 and 2 operating licenses (Operating License Nos. NPF-39 and NPR-85) for a period of 20 years beyond the current expiration at midnight October 26, 2024, and June 22, 2029, respectively.

LGS is located approximately 21 miles northwest of Philadelphia, PA. The NRC issued the LGS Units 1 and 2 construction permits on June 19, 1974, and the operating licenses for LGS Unit 1 on August 8, 1985, and LGS Unit 2 on August 25, 1989. LGS Units 1 and 2 are of a boiling-water reactor design. General Electric supplied the nuclear steam supply system and Bechtel originally designed and constructed the balance of the plant. LGS Units 1 and 2 both have a licensed power output of 3,515 megawatts thermal.

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ABBREVIATIONS

AAI	applicant action item
ACI	American Concrete Institute
ACRS	Advisory Committee on Reactor Safeguards
ADAMS	Agencywide Documents Access and Management System
AERM	aging effect requiring management
AFW	auxiliary feedwater
AMP	aging management program
AMR	aging management review
ANSI	American National Standards Institute
ART	adjusted reference temperature
ASCE	American Society of Civil Engineers
ASME	American Society of Mechanical Engineers
AST	alternate source term
ASTM	American Society for Testing and Materials
ATWS	anticipated transient without scram
B&W	Babcock and Wilcox
BTP	branch technical position
BWR	boiling-water reactor
BWRVIP	Boiling Water Reactor Vessel Integrity Project
CAP	corrective action program
CASS	cast austenitic stainless steel
CFR	*Code of Federal Regulations*
CLB	current licensing basis
CMAA	Crane Manufacturers Association of America
CMRT	certified material test record
CRD	control rod drive
CRL	component record list
CSC	containment spray cooling
CS	core spray
CST	condensate storage tank
Cu	copper
CUF	cumulative usage factor
CuF_{en}	environmentally adjusted fatigue usage factor
CW	circulating water
DBA	design-basis accident
DBE	design-basis event
EAF	environmentally assisted fatigue
ECCS	emergency core cooling system
EDG	emergency diesel generator
EFPY	effective full-power year
EMA	equivalent margins analysis
EPRI	Electric Power Research Institute
EQ	environmental qualification

ESF	engineered safety features
ESW	emergency service water
F_{en}	environmental fatigue life correction factor
FERC	Federal Energy Regulatory Commission
FIV	flow induced vibration
FR	*Federal Register*
ft-lb	foot-pound
GALL	Generic Aging Lessons Learned Report
GDC	general design criteria or general design criterion
GE	General Electric
GEIS	generic environmental impact statement
GL	generic letter
GSI	generic safety issue
HELB	high-energy line break
HPCI	high-pressure coolant injection
HPSI	high-pressure safety injection
HVAC	heating, ventilation, and air conditioning
I&C	instrumentation and controls
IASCC	irradiation assisted stress corrosion cracking
ICMH	in-core monitoring housing
ID	inside diameter
IGSCC	intergranular stress corrosion cracking
ILRT	integrated leak rate test
IN	information notice
INPO	Institute of Nuclear Power Operations
IPA	integrated plant assessment
ISG	interim staff guidance
ISI	inservice inspection
ISP	Integrated Surveillance Program
kV	kilovolt
LBB	leak-before-break
LER	licensee event report
LGS	Limerick Generating Station
LLRT	local leak rate test
LOCA	loss-of-coolant accident
LPCI	low-pressure coolant injection
LPRM	low-power range monitor
LRA	license renewal application
LTOP	low-temperature overpressure protection
MC	metal containment
MEB	metal enclosed bus
MIC	microbiologically influenced corrosion
MoS_2	molybdenum disulfide

MSIP	mechanical stress improvement process
MSIV	main steam isolation valve
MSRV	main steam relief valve
MUR	measurement uncertainty recapture
n/cm^2	neutrons per square centimeter
NDE	nondestructive examination
NEI	Nuclear Energy Institute
NFPA	National Fire Protection Association
Ni	nickel
NPS	nominal pipe size
NRC	U.S. Nuclear Regulatory Commission
NRR	Office of Nuclear Reactor Regulation
OBE	operational basis earthquake
OE	operating experience
OI	open item
PCIG	primary containment instrument gas
PDL	Plastics Design Library
pH	potential of hydrogen
P&ID	plant piping and instrumentation drawing
PoF	probability of failure
P-T	pressure-temperature
PTS	pressurized thermal shock
PVC	polyvinyl chloride
PWR	pressurized-water reactor
PWSCC	primary water stress corrosion cracking
QA	quality assurance
QAP	quality assurance program
RAI	request for additional information
RAMA	Radiation Analysis Modeling Application
RCIC	reactor core isolation cooling
RCP	reactor coolant pump
RCPB	reactor coolant pressure boundary
RCS	reactor coolant system
RCSC	Research Council for Structural Connections
RG	regulatory guide
RHR	residual heat removal
RHRSW	residual heat removal service water
RI-ISI	risk-informed inservice inspection
RPV	reactor pressure vessel
RT_{NDT}	reference temperature nil ductility transition
RVI	reactor vessel internals
RWCU	reactor water cleanup

SBO	station blackout
SC	structure and component
SCC	stress corrosion cracking
SDC	shutdown cooling
SDV	scram discharge volume
SER	safety evaluation report
SGTS	standby gas treatment system
SLC	standby liquid control
SOER	significant operating experience reports
SPC	suppression pool cooling
SPU	stretch power uprate
SRP	standard review plan
SRP-LR	"Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants"
SRV	safety relief valve
SSC	system, structure, and component
SSE	safe-shutdown earthquake
SW	service water
TIP	traversing in-core probe
TLAA	time-limited aging analysis
TS	technical specifications
TTA	tolyltriazole
UFSAR	updated final safety analysis report
USE	upper-shelf energy
UT	ultrasonic examinationUV ultraviolet
VFLD	vessel flange leak detector
WLI	water level instrumentation
WTD	water treatment and distribution
yr	year
Zn	zinc

SECTION 1

INTRODUCTION AND GENERAL DISCUSSION

1.1 Introduction

This document is a safety evaluation report (SER) on the license renewal application (LRA) for Limerick Generating Station (LGS), Units 1 and 2, as filed by Exelon Generation Company, LLC (Exelon or the applicant). By letter dated June 22, 2011, Exelon submitted its application to the United States (U.S.) Nuclear Regulatory Commission (NRC) for renewal of the LGS operating licenses for an additional 20 years. The staff prepared this report to summarize the results of its safety review of the LRA for compliance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants." The NRC project manager for the license renewal review is Robert Kuntz. Mr. Kuntz may be contacted by telephone at 301-415-3733 or by email at robert.kuntz@nrc.gov. Alternatively, written correspondence may be sent to the following address:

Division of License Renewal
U.S. Nuclear Regulatory Commission
Washington, DC 20555-0001
Attention: Robert Kuntz, Mail Stop 011-F1

In its June 22, 2011, submission letter, the applicant requested renewal of the operating licenses issued under Section 103 (Operating Licenses No. NPF-39 and NPF-85) of the Atomic Energy Act of 1954, as amended, for LGS Units 1 and 2 for a period of 20 years beyond the current expiration at midnight October 26, 2024, and June 22, 2029, respectively. LGS is located approximately 21 miles northwest of Philadelphia, PA. The NRC issued the LGS Units 1 and 2 construction permits on June 19, 1974, and the operating license for LGS Unit 1 on August 8, 1985, and LGS Unit 2 on August 25, 1989. LGS Units 1 and 2 are of a boiling-water reactor design. General Electric supplied the nuclear steam supply system and Bechtel originally designed and constructed the balance of the plant. LGS Units 1 and 2 both have a licensed power output of 3,515 megawatts thermal. The updated final safety analysis report (UFSAR) shows details of the plant and the site.

The license renewal process consists of two concurrent reviews, a technical review of safety issues and an environmental review. The NRC regulations in 10 CFR Part 54 and 10 CFR Part 51, "Environmental Protection Regulations for Domestic Licensing and Related Regulatory Functions," respectively, set forth requirements for these reviews. The safety review for the LGS license renewal is based on the applicant's LRA and responses to the staff's requests for additional information (RAIs). The applicant supplemented the LRA and provided clarifications through its responses to the staff's RAIs in audits, meetings, and docketed correspondence. Unless otherwise noted, the staff reviewed and considered information submitted through July 11, 2012. The staff reviewed information received after this date depending on the stage of the safety review and the volume and complexity of the information. The public may view the LRA and all pertinent information and materials, including the UFSAR, at the NRC Public Document Room located on the first floor of One White Flint North, 11555 Rockville Pike, Rockville, MD 20852-2738 (301-415-4737 or 800-397-4209), and at

Pottstown Regional Public Library, 500 East High Street, Pottstown, PA 19464-5656. In addition, the public may find the LRA, as well as materials related to the license renewal review, on the NRC website at http://www.nrc.gov.

This SER summarizes the results of the staff's safety review of the LRA and describes the technical details considered in evaluating the safety aspects of proposed operation of Units 1 and 2 for an additional 20 years beyond the term of the current operating licenses. The staff reviewed the LRA in accordance with NRC regulations and the guidance in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), issued December 2010.

SER Sections 2 through 4 address the staff's evaluation of license renewal issues considered during the review of the application. SER Section 5 is reserved for the report of the Advisory Committee on Reactor Safeguards (ACRS). The SER conclusions are in Section 6.

SER Appendix A is a table showing the applicant's commitments for renewal of the operating licenses. SER Appendix B is a chronology of the principal correspondence between the staff and the applicant regarding the LRA review. SER Appendix C is a list of principal contributors to the SER, and Appendix D is a bibliography of the references in support of the staff's review.

In accordance with 10 CFR Part 51, the staff prepared a draft plant-specific supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)." This supplement discusses the environmental considerations for license renewal for LGS Units 1 and 2. The staff plans to issue a draft, plant-specific GEIS supplement. The final, plant-specific GEIS supplement will then be issued after consideration of public comment on the draft plant-specific GEIS.

1.2 License Renewal Background

Pursuant to the Atomic Energy Act of 1954, as amended, and NRC regulations, operating licenses for commercial power reactors are issued for 40 years and can be renewed for up to 20 additional years. The original 40-year license term was selected based on economic and antitrust considerations rather than on technical limitations; however, some individual plant and equipment designs may have been engineered for an expected 40-year service life.

In 1982, the staff anticipated interest in license renewal and held a workshop on nuclear power plant aging. This workshop led the NRC to establish a comprehensive program plan for nuclear plant aging research. From the results of that research, a technical review group concluded that many aging phenomena are readily manageable and pose no technical issues precluding life extension for nuclear power plants. In 1986, the staff published a request for comment on a policy statement that would address major policy, technical, and procedural issues related to license renewal for nuclear power plants.

In 1991, the staff published 10 CFR Part 54, the License Renewal Rule (Volume 56, page 64943, of the *Federal Register* (FR) (56 FR 64943), dated December 13, 1991). The staff participated in an industry-sponsored demonstration program to apply 10 CFR Part 54 to a pilot plant and to gain the experience necessary to develop implementation guidance. To establish a scope of review for license renewal, 10 CFR Part 54 defined age-related degradation unique to license renewal. However, during the demonstration program, the staff found that adverse aging effects on plant systems and components are managed during the initial license period and that the scope of the review did not allow sufficient credit for management programs, particularly the implementation of 10 CFR 50.65, "Requirements for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," which regulates management of plant-aging phenomena. As a result of this finding, the staff amended 10 CFR Part 54 in 1995. As published May 8, 1995, (60 FR 22461), amended 10 CFR Part 54 establishes a simpler, more stable, and more predictable regulatory process than the previous 10 CFR Part 54. In particular, as amended, 10 CFR Part 54 focuses on the management of adverse aging effects rather than on the identification of age-related degradation unique to license renewal. The staff made these rule changes to ensure that important systems, structures, and components (SSCs) will continue to perform their intended functions during the period of extended operation. In addition, the amended 10 CFR Part 54 clarifies and simplifies the integrated plant assessment (IPA) process to be consistent with the revised focus on passive, long-lived structures and components (SCs).

Concurrent with these initiatives, the staff pursued a separate rulemaking effort (61 FR 28467, June 5, 1996) and amended 10 CFR Part 51 to focus the scope of the review of environmental impacts of license renewal to fulfill NRC responsibilities under the National Environmental Policy Act of 1969.

1.2.1 Safety Review

License renewal requirements for power reactors are based on two key principles:

(1) The regulatory process is adequate to ensure that the licensing bases of all currently operating plants maintain an acceptable level of safety, with the possible exceptions of the detrimental aging effects on the functions of certain SSCs, as well as a few other safety-related issues, during the period of extended operation.

(2) The plant-specific licensing basis must be maintained during the renewal term in the same manner and to the same extent as during the original licensing term.

In implementing these two principles, 10 CFR 54.4, "Scope," defines the scope of license renewal as including those SSCs that (1) are safety-related, (2) whose failure could affect safety-related functions, or (3) are relied on to demonstrate compliance with the NRC's regulations for fire protection, environmental qualification (EQ), pressurized thermal shock (PTS), anticipated transient without scram (ATWS), and station blackout (SBO).

Pursuant to 10 CFR 54.21(a), a license renewal applicant must review all SSCs within the scope of 10 CFR Part 54 to identify SCs subject to an aging management review (AMR). Those SCs subject to an AMR perform an intended function without moving parts or without change in configuration or properties and are not subject to replacement based on a qualified life or specified time period. Pursuant to 10 CFR 54.21(a), a license renewal applicant must demonstrate that the aging effects will be managed such that the intended function(s) of those SCs will be maintained consistent with the current licensing basis (CLB) for the period of extended operation. However, active equipment is considered to be adequately monitored and maintained by existing programs. In other words, detrimental aging effects that may affect active equipment can be readily identified and corrected through routine surveillance, performance monitoring, and maintenance. Surveillance and maintenance programs for active

equipment, as well as other maintenance aspects of plant design and licensing basis, are required throughout the period of extended operation.
In accordance with 10 CFR 54.21(d), the LRA is required to include a UFSAR supplement with a summary description of the applicant's programs and activities for managing aging effects and an evaluation of time-limited aging analyses (TLAAs) for the period of extended operation.

License renewal also requires TLAA identification and updating. During the plant design phase, certain assumptions about the length of time the plant can operate are incorporated into design calculations for several plant SSCs. In accordance with 10 CFR 54.21(c)(1), the applicant must either show that these calculations will remain valid for the period of extended operation, project the analyses to the end of the period of extended operation, or demonstrate that the aging effects on these SSCs will be adequately managed for the period of extended operation.

In 2005, the NRC revised Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications to Renew Nuclear Power Plant Operating Licenses." This RG endorses Nuclear Energy Institute (NEI) 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule," issued in June 2005. NEI 95-10 details an acceptable method of implementing 10 CFR Part 54. The staff also used the SRP-LR to review the LRA.

In the LRA, the applicant fully used the process defined in NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," issued December 2010. The GALL Report summarizes staff-approved aging management programs (AMPs) for many SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review can be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report summarizes the aging management evaluations, programs, and activities credited for managing aging for most of the SCs used throughout the industry. The report also is a quick reference for both applicants and staff reviewers to AMPs and activities that can manage aging adequately during the period of extended operation.

1.2.2 Environmental Review

Regulations on environmental protection are contained in 10 CFR Part 51. In December 1996, the staff revised the environmental protection regulations to facilitate the environmental review for license renewal. The staff prepared the GEIS to document its evaluation of possible environmental impacts associated with nuclear power plant license renewals. For certain types of environmental impacts, the GEIS contains generic findings that apply to all nuclear power plants and are codified in Appendix B, "Environmental Effect of Renewing the Operating License of a Nuclear Power Plant," to Subpart A, "National Environmental Policy Act – Regulations Implementing Section 102(2)," of 10 CFR Part 51. Pursuant to 10 CFR CFR 51.53(c)(3)(i), a license renewal applicant may incorporate these generic findings in its environmental report. In accordance with 10 CFR 51.53(c)(3)(ii), an environmental report also must include analyses of environmental impacts that must be evaluated on a plant-specific basis (i.e., Category 2 issues).

In accordance with the National Environmental Policy Act of 1969 and 10 CFR Part 51, the staff is reviewing the plant-specific environmental impacts of license renewal, including whether there is new and significant information not considered in the GEIS. As part of its scoping process, the staff held a public meeting on September 22, 2011, at the Sunnybrook Ballroom, 50 North

Sunnybrook Road, Pottstown, PA 19464, to identify plant-specific environmental issues. The draft plant-specific GEIS supplement will document the results of the environmental review and will make a preliminary recommendation as to the license renewal action. The staff will hold another public meeting to discuss the draft plant-specific GEIS supplement. After considering comments on the draft, the staff will publish the final plant-specific GEIS separately from this report.

1.3 Principal Review Matters

Requirements for renewal of operating licenses for nuclear power plants are described in 10 CFR Part 54. The staff's technical review of the LRA was in accordance with NRC guidance and 10 CFR Part 54 requirements. The license renewal standards are set forth in 10 CFR 54.29, "Standards for Issuance of a Renewed License." This SER describes the results of the staff's safety review.

In accordance with 10 CFR 54.19(a), the NRC requires a license renewal applicant to submit general information, which the applicant provided in LRA Section 1. The staff reviewed LRA Section 1 and finds that the applicant has submitted the required information.

In accordance with 10 CFR 54.19(b), the NRC requires that the LRA include "conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." On this issue, the applicant stated in the LRA:

> 10 CFR 54.19(b) requires that "each application must include conforming changes to the standard indemnity agreement, 10 CFR 140.92, Appendix B, to account for the expiration term of the proposed renewed license." The current indemnity agreement (B-101) for LGS states in Article VII that the agreement shall terminate at the time of expiration of that license specified in Item 3 of the Attachment to the agreement, which is the last to expire; provided that, except as may otherwise be provided in applicable regulations or orders of the Commission, the term of this agreement shall not terminate until all the radioactive material has been removed from the location and transportation of the radioactive material from the location has ended as defined in subparagraph 5(b), Article I. Item 3 of the Attachment to the indemnity agreement includes license number SNM-1926. Applicant requests that any necessary conforming changes be made to Article VII and Item 3 of the Attachment, and any other sections of the indemnity agreement as appropriate to ensure that the indemnity agreement continues to apply during both the terms of the current licenses and the terms of the renewed licenses. Applicant understands that no changes may be necessary for this purpose if the current license numbers are retained.

The staff intends to maintain the original license numbers upon issuance of the renewed licenses, if approved. Therefore, conforming changes to the indemnity agreement need not be made and the 10 CFR 54.19(b) requirements have been met.

In accordance with 10 CFR 54.21, "Contents of Application – Technical Information," the NRC requires that the LRA contain (a) an IPA, (b) a description of any CLB changes during the staff's review of the LRA, (c) an evaluation of TLAAs, and (d) an UFSAR supplement. LRA Sections 3 and 4 and Appendix B address the license renewal requirements of 10 CFR 54.21(a), (b), and (c). LRA Appendix A satisfies the license renewal requirements of 10 CFR 54.21(d).

In accordance with 10 CFR 54.21(b), the NRC requires that each year following submission of the LRA and at least 3 months before the scheduled completion of the staff's review, the applicant submit an LRA amendment identifying any CLB changes to the facility that affect the contents of the LRA, including the UFSAR supplement. By letter dated June 14, 2012, the applicant submitted an LRA update, which summarizes the CLB changes that have occurred during the staff's review of the LRA. This submission satisfies 10 CFR 54.21(b) requirements and is still under staff review.

Pursuant to 10 CFR 54.22, "Contents of Application – Technical Specifications," the NRC requires that the LRA include changes or additions to the technical specifications (TS) necessary to manage aging effects during the period of extended operation. In LRA Appendix D, the applicant stated that it had not identified any TS changes necessary for issuance of the renewed LGS Units 1 and 2 operating licenses. This statement adequately addresses the 10 CFR 54.22 requirements.

The staff evaluated the technical information required by 10 CFR 54.21 and 10 CFR 54.22 in accordance with NRC regulations and SRP-LR guidance. SER Sections 2, 3, and 4 document the staff's evaluation of the LRA technical information.

As required by 10 CFR 54.25, "Report of the Advisory Committee on Reactor Safeguards," ACRS will issue a report documenting its evaluation of the staff's LRA review and SER. SER Section 5 is reserved for the ACRS report when it is issued. SER Section 6 documents the findings required by 10 CFR 54.29.

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. Interim staff guidance (ISG) is documented for use by the staff, industry, and other interested stakeholders until incorporated into such license renewal guidance documents as the SRP-LR and the GALL Report.

Table 1.4-1 shows the current set of ISGs, as well as the SER sections in which the staff addresses them.

Table 1.4-1 Current Interim Staff Guidance

ISG Issue (Approved ISG Number)	Purpose	SER Section
"Staff Guidance for Preparing Severe Accident Mitigation Alternatives Analyses" (LR-ISG-2006-03)	This ISG is related to severe accident management alternatives for environmental impact statements	N/A for the SER
"Ongoing Review of Operating Experience" (LR-ISG-2011-05)	This LR-ISG clarifies the staff's existing position in the SRP-LR that acceptable license renewal AMPs should be informed and enhanced when necessary, based on the ongoing review of both plant-specific and industry operating experience.	SER Section 3.0.5

1.5 Summary of Open Items

As a result of its review of the LRA, including additional information submitted through July 11, 2012, the staff had identified the following open items (OI) when it issued the SER with Open Items on July 30, 2012. An item is considered open if, in the staff's judgment, it does not meet all applicable regulatory requirements at the time of the issuance of this SER. The staff has assigned a unique identifying number to each OI.

Open Item 3.0.3.2.13-1 ASME Code Section XI, Subsection IWE

LGS Units 1 and 2 have seen corrosion in the suppression pool liner and downcomers. The applicant's proposed aging management of the suppression pool liner and downcomers is within the scope of the American Society of Mechanical Engineers (ASME) Code Section XI, Subsection IWE program. As described in SER Section 3.0.3.2.13, the staff had an open item for aging management of the suppression pool liner and downcomers. Specifically, the open item was related to the following concerns:

- The applicant has developed an acceptance criterion for the degradation of the downcomers; however, this criterion is not identified in the AMP or the associated procedures.
- The criteria used for selecting locations for recoating (i.e., criteria for coating degradation, general corrosion, and pitting corrosion) may not be adequate. In addition, it is not clear how the coating degradation can be effectively identified for each liner plate underwater in the suppression pool. Also, the applicant's proposed criteria for augmented inspection is not consistent with the ASME Code, Section XI, Subsection IWE requirement that detailed visual and ultrasonic thickness measurement be completed on 100 percent of surface areas subjected to accelerated corrosion or areas where the absence or repeated loss of coatings has resulted in substantial corrosion or pitting.

Based on its audit and review of the application, and review of the applicant's response to the open item, 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 GALL Report AMP. Open Item 3.0.3.2.13-1 is closed.

Open Item 3.0.5.1 Operating Experience for Aging Management Programs

LR-ISG-2011-05 states that enhancements to the existing programmatic activities for the ongoing review of operating experience that are necessary for license renewal should be put in place no later than the date the renewed operating licenses are issued. The applicant described several enhancements; however, it planned to implement them after issuance of the renewed licenses. As discussed in SER Section 3.0.5, the staff could not determine whether operating experience related to aging management and age-related degradation will be considered in the period between issuance of the renewed licenses and implementation of the enhancements. In response, the applicant stated that the enhancements to the Operating Experience program will be implemented no later than the date when the renewed operating licenses are issued and conducted on an ongoing basis throughout the terms of the renewed licenses. The staff finds this implementation schedule acceptable because it is consistent with the guidance in LR-ISG-2011-05. Implementation of these enhancements will ensure that the applicant fully considers all available information to inform the aging management activities on an ongoing basis throughout the terms of the renewed licenses. Open Item 3.0.5-1 is closed.

1.6 Summary of Confirmatory Items

As a result of its review of the LRA, including additional information submitted through July 11, 2012 the staff determines that no confirmatory items exist that would require a formal response from the applicant.

1.7 Summary of Proposed License Conditions

Following the staff's review of the LRA, including subsequent information and clarifications from the applicant, the staff identified two proposed license conditions.

The first license condition requires the applicant to include the UFSAR supplement required by 10 CFR 54.21(d) in the next UFSAR update, required by 10 CFR 50.71(e), following the issuance of the renewed licenses. The applicant may make changes to the programs and activities described in the UFSAR supplement, provided the applicant evaluates such changes in accordance with the criteria set forth in 10 CFR 50.59 and otherwise complies with the requirements in that section.

The second license condition requires future activities described in the UFSAR supplement to be completed before the period of extended operation. In its SER with Open Items issued on July 30, 2012, the staff proposed that the applicant shall complete these activities no later than six months before the period of extended operation, and shall notify the NRC in writing when implementation of these activities is complete. In particular, the NRC is directing the applicant to complete certain license renewal activities no later than 6 months prior to PEO in order to ensure the completion of its inspection requirements under NRC Inspection Procedure (IP) 71003, "Post-Approval Site Inspection for License Renewal." Through this IP, the staff verifies that the license renewal commitments and selected AMPs are satisfactorily implemented, the description of the AMPs and related activities are, or will be, contained in the

UFSAR, and the description of the programs is consistent with the programs implemented by the licensee. Notwithstanding the "Enhancement or Implementation Schedule" detailed in Appendix A, "Limerick Generating Station, Units 1 and 2, License Renewal Commitments," to this SER and the NRC staff's findings presented in various sections of the SER, the scheduler requirements proposed in the second license condition shall take precedence.

In a letter dated October 12, 2012, the applicant provided its comments on this license condition. The applicant stated that this proposed license condition would require completion of most activities described in the license renewal commitment list six months earlier than it had committed to perform these activities. The applicant further stated that the proposed license condition creates consequences that the staff may not have intended or appreciated. Specifically, the current operating licenses for Units 1 and 2 expire on October 26, 2024, and June 22, 2029, respectively, and the applicant performs its refueling outages in the spring. A license condition requiring that the activities be completed at least six months prior to entering the PEO would mean that the applicant would not have the opportunity to perform inspections during the last scheduled refueling outage prior to PEO for Units 1 or 2. Thus, the applicant concluded that by not allowing aging management activities to be performed in the last refueling outage prior to the PEO, there are additional undesirable consequences. For example, certain aging management programs specifically require that inspections be done close to the PEO to allow more time for aging effects to develop and be detected by inspection.

The staff reviewed the applicant's comments and supporting basis and found that certain aspects of the proposed license condition could preclude scheduling actions to both obtain better performance of the specific aging management program activities and make more use of outage work periods. On this basis, the proposed second license condition was revised to state that:

> The applicant's UFSAR supplement submitted pursuant to 10 CFR 54.21(d), as revised during the license renewal application review process, describes certain programs to be implemented and activities to be completed prior to the period of extended operation.
>
> a. The applicant shall implement those new programs and enhancements to existing programs no later than 6 months prior to PEO.
>
> b. The applicant shall complete those activities as noted in Commitment Nos. 18, 19, 20, 22, 23, 24, 28, 29, 30, 38, 39, 40, 41, 42, 43, and 47 of Appendix A of NUREG-XXXX, "Limerick Safety Evaluation Report for License Renewal," by the 6-month date prior to PEO or the end of the last refueling outage prior to the PEO, whichever occurs later.
>
> The applicant shall notify the NRC in writing within 30 days after having accomplished item (a) above and include the status of those activities that have been or remain to be completed in item (b) above.

SECTION 2

STRUCTURES AND COMPONENTS SUBJECT TO AGING MANAGEMENT REVIEW

2.1 Scoping and Screening Methodology

2.1.1 Introduction

Title 10 of the *Code of Federal Regulations (*10 CFR) 54.21, "Contents of Application – Technical Information," requires Exelon Generation Company, LLC (Exelon or the applicant) to identify the structures, systems, and components (SSCs) within the scope of license renewal in accordance with 10 CFR 54.4(a). In addition, the license renewal application (LRA) must contain an integrated plant assessment (IPA) that identifies and lists those structures and components (SCs), contained in the SSCs identified to be within the scope of license renewal, that are subject to an aging management review (AMR).

2.1.2 Summary of Technical Information in the Application

LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results," provides the technical information required by 10 CFR 54.21(a).

LRA Section 2.1, "Scoping and Screening Methodology," describes the methodology used by the applicant to identify the SSCs at the Limerick Generating Station (LGS), Units 1 and 2, within the scope of license renewal (scoping) and the SCs subject to an AMR (screening).

LRA Section 2.1.1, "Introduction," states, in part, that the applicant had considered the following in developing the scoping and screening methodology described in LRA Section 2:

- 10 CFR Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," (the rule)
- Nuclear Energy Institute (NEI) 95-10, Revision 6, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule," issued June 2005 (NEI 95-10)

2.1.3 Scoping and Screening Program Review

The staff of the U.S. Nuclear Regulatory Commission (NRC) (the staff) evaluated the applicant's scoping and screening methodology in accordance with the guidance contained in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," (SRP-LR), Section 2.1, "Scoping and Screening Methodology." The following regulations provide the basis for the acceptance criteria the staff used to assess the adequacy of the scoping and screening methodology that the applicant used to develop the LRA:

- 10 CFR 54.4(a), as it relates to the identification of SSCs within the scope of the rule

- 10 CFR 54.4(b), as it relates to the identification of the intended functions of SSCs within the scope of the rule
- 10 CFR 54.21(a), as it relates to the methods used by the applicant to identify plant SCs subject to an AMR

The staff reviewed the information in LRA Section 2.1 to ensure that the applicant described a process for identifying SSCs that are within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a) and the SCs that are subject to an AMR in accordance with the requirements of 10 CFR 54.21(a).

In addition, the staff conducted a scoping and screening methodology audit at the LGS site during the week of September 19–23, 2011. The audit focused on ensuring that the applicant had developed and implemented adequate guidance to conduct the scoping and screening of SSCs in accordance with the methodology described in the LRA and the requirements of the rule. The staff reviewed the project-level guidelines, topical reports, and implementing procedures that described the applicant's scoping and screening methodology. The staff conducted detailed discussions with the applicant on the development of the license renewal application, the quality practices the applicant used during LRA development, and the training of the applicant's staff that participated in LRA development. On a sampling basis, the staff performed a review of scoping and screening results reports and supporting current licensing basis (CLB) information for the safety-related service water (SW) system and the turbine building. In addition, the staff performed walkdowns of selected portions of the essential SW system, fuel pool cooling and cleanup system, emergency diesel generator (EDG) fuel oil transfer subsystem, EDG air start subsystem, and the turbine building, as a part of the sampling review of the implementation of the applicant's 10 CFR 54.4(a)(2) scoping methodology.

2.1.3.1 Implementation Procedures and Documentation Sources for Scoping and Screening

The staff reviewed the applicant's scoping and screening implementing procedures, as documented in the "Scoping and Screening Methodology Audit Report Regarding the Limerick Generating Station, Units 1 and 2," dated December 9, 2011, to verify that the process used to identify SSCs within the scope of license renewal and SCs subject to an AMR was consistent with the SRP-LR. Additionally, the staff reviewed the scope of CLB documentation and the process the applicant used, relative to the requirements of 10 CFR 54.4, "Scope," and 10 CFR 54.21, and it confirmed that the applicant adequately implemented its procedural guidance during the scoping and screening process.

2.1.3.1.1 Summary of Technical Information in the Application

In LRA Section 2.1, the applicant addressed the following information sources for the license renewal scoping and screening process:

- updated final safety analysis report (UFSAR)
- fire protection evaluation report
- environmental qualification (EQ) master list
- maintenance rule database

- design baseline documents
- component record list (CRL)
- other CLB references, such as NRC safety evaluation reports (SERs), licensing correspondence, engineering drawings, and engineering evaluations and calculations

2.1.3.1.2 Staff Evaluation

Scoping and Screening Implementation Procedures. The staff reviewed the applicant's scoping and screening methodology implementing procedures, including license renewal guidelines, documents and reports, as documented in the staff's audit report, to ensure that the guidance is consistent with the requirements of the rule, and with the guidance in the SRP-LR and Regulatory Guide (RG) 1.188, "Standard Format and Content for Applications To Renew Nuclear Plant Operating Licenses," which endorses the use of NEI 95-10. The staff finds the overall process used to implement the 10 CFR Part 54 requirements described in the implementing procedures and AMRs is consistent with the rule, the SRP-LR, and the NRC-endorsed industry guidance.

The applicant's implementing procedures contain guidance for determining plant SSCs within the scope of the rule and SCs contained in systems within the scope of license renewal that are subject to an AMR. During the review of the implementing procedures, the staff focused on the consistency of the detailed procedural guidance with information contained in the LRA, including the implementation of staff positions documented in the SRP-LR, and the information in the applicant's responses dated January 27, 2012, to the staff's requests for additional information (RAIs), dated January 5, 2012.

After reviewing the LRA and supporting documentation, the staff determined that the scoping and screening methodology instructions are consistent with the methodology description provided in LRA Section 2.1. The applicant's methodology is sufficiently detailed in the implementing procedures to provide concise guidance on the scoping and screening process to be followed during the LRA activities.

Sources of CLB Information. Regulations in 10 CFR 54.21(a)(3) require for each structure and component determined to be subject to an AMR to demonstrate that the effects of aging will be adequately managed so that the intended functions will be maintained consistent with the CLB for the period of extended operation. The CLB is defined in 10 CFR 54.3(a), in part, as the set of NRC requirements applicable to a specific plant and an applicant's written commitments for ensuring compliance with, and operation within, applicable NRC requirements and the plant-specific design bases that are docketed and in effect. The CLB includes applicable NRC regulations, orders, license conditions, exemptions, technical specifications, and design-basis information (documented in the most recent UFSAR). The CLB also includes licensee commitments remaining in effect that were made in docketed licensing correspondence, such as licensee responses to NRC bulletins, generic letters, and enforcement actions, and licensee commitments documented in NRC safety evaluations or licensee event reports.

During the scoping and screening methodology audit, the staff confirmed that the applicant's detailed license renewal program guidelines specified the use of the CLB source information in developing scoping evaluations. The staff reviewed pertinent information sources that the applicant used, including the UFSAR, design-basis information, and plant piping and instrumentation drawings (P&IDs). In addition, the staff determined that the applicant had used additional sources of plant information pertinent to the scoping and screening process, including the CRL, analyses, and reports.

The staff determined that the applicant's primary repository for system identification and component safety classification information was the CRL, UFSAR, and P&IDs. During the audit, the staff discussed the applicant's administrative controls for the CRL and the other information sources used to verify system information. These controls are described and implemented by plant procedures. Based on a review of the administrative controls, and a sample of the system classification information contained in the applicable documentation, the staff concludes that the applicant has established adequate measures to control the integrity and reliability of system identification and safety classification data; therefore, the staff determined that the information sources the applicant used during the scoping and screening process provided a controlled source of system and component data to support scoping and screening evaluations.

In addition, the staff reviewed the implementing procedures and results reports used to support identification of SSCs that the applicant relied on to demonstrate compliance with the requirements of 10 CFR 54.4(a). The applicant's license renewal program guidelines provided a list of documents used to support scoping evaluations. The staff determined that the design documentation sources, required to be used by the applicant's implementing procedures, provided sufficient information to ensure that the applicant identified SSCs to be included within the scope of license renewal that were consistent with the plant's CLB.

The staff determined additional information would be required to complete its review. The staff noted that several plant systems discussed in the UFSAR are not identified in the LRA. During the audit, discussions with the applicant indicated that systems nomenclature had been organized to correspond with the system information contained in NUREG-1801, "Generic Aging Lessons Learned (GALL) Report." Therefore, the staff issued RAI 2.1-2, dated January 5, 2012, requesting the applicant to provide a description of the process used to identify systems to be included within the scope of license renewal in accordance with 10 CFR 54.4(a) and to provide a discussion on the process used to identify systems listed in the UFSAR with system names discussed in the GALL Report.

The applicant responded to RAI 2.1-2, by letter dated January 27, 2012, stating that the comprehensive list of plant systems and structures contained in the plant component record database was evaluated and arranged into logical groupings for license renewal evaluation, and the groupings were defined as license renewal systems and structures.

The applicant's response to RAI 2.1-2 further stated that the distinction between plant systems and license renewal systems falls into several categories. The categories are summarized as follows:

- GALL Report system names used to identify and group together plant systems or structures for license renewal
- plant system and structure descriptive titles modified to encompass various descriptive nomenclature used across multiple plant documents
- plant systems and structures described in the UFSAR that perform the same function grouped together to facilitate a streamlined license renewal evaluation, where appropriate

In addition, the applicant's response to RAI 2.1-2 stated that a review of this issue was performed, and it was concluded that the scoping methodology correctly identified the SSCs that should be included within the scope of license renewal in accordance with 10 CFR 54.4(a). The response also stated that there are no additional scoping evaluations required or additional SSCs to be included, and no additions or changes to LRA Table 2.2-1 have been identified as a result of the applicant's review.

The staff reviewed the response to RAI 2.1-2 and determined that the applicant had provided a description of the process used to identify systems within the scope of license renewal and had, in some instances, collected plant systems and identified the collection to be in alignment with the terminology used in the GALL Report. In addition, the staff determined that the applicant had performed a review of the issue and concluded that all SSCs had been appropriately evaluated for inclusion within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a). RAI 2.1-2 is resolved.

2.1.3.1.3 Conclusion

Based on its review of LRA Section 2.1, the detailed scoping and screening implementing procedures, the applicant's response to RAI 2.1-2, and the results from the scoping and screening audit, the staff concludes that the applicant's use of implementing procedures and consideration of document sources, including CLB information, is consistent with the rule, the SRP-LR, and NEI 95-10 guidance and, therefore, is acceptable.

2.1.3.2 Quality Controls Applied to LRA Development

2.1.3.2.1 Staff Evaluation

The staff reviewed the quality controls the applicant used to ensure that the scoping and screening methodology used to develop the LRA was adequately implemented. The applicant used the following quality control processes during the LRA development:

- Scoping and screening activities were performed using controlled documents and procedures.
- Databases were used to guide and support screening and scoping and generate license renewal documents.
- Scoping and screening activities were conducted, documented, reviewed, and approved in accordance with controlled procedures.

During the scoping and screening methodology audit, the staff performed a sample review of reports and LRA development procedures and guides, the applicant's documentation of the activities performed to assess the quality of the LRA, and held discussions with the applicant's license renewal personnel. The staff determined that the applicant's activities provide assurance that LRA development activities were performed consistently with the applicant's license renewal program requirements.

2.1.3.2.2 Conclusion

Based on its review of pertinent LRA development guidance, discussion with the applicant's license renewal staff, and review of the applicant's documentation of the activities performed to assess the quality of the LRA, the staff concludes that the applicant's quality assurance activities provide assurance that LRA development activities were performed in accordance with the applicant's license renewal program requirements.

2.1.3.3 Training

2.1.3.3.1 Staff Evaluation

The staff reviewed the applicant's training processes to ensure that the guidelines and methodology for the scoping and screening activities were adequately implemented. As outlined in the implementing procedure, the applicant requires training for personnel participating in the development of the LRA. The activities conducted by the applicant included the following:

- training of personnel participating in license renewal to the applicable project procedures and other relevant license renewal information, as appropriate to their functions
- license renewal and subject matter expert training, including:
  - 10 CFR Part 54
  - relevant NRC and industry guidance documents
  - lessons learned from previous license renewals
  - applicable procedures

During the scoping and screening methodology audit, the staff reviewed the applicant's written procedures. On a sampling basis, the staff reviewed completed qualification and training records and completed checklists for a sample of the applicant's license renewal personnel.

2.1.3.3.2 Conclusion

Based on discussions with the applicant's license renewal personnel responsible for the scoping and screening process and its review of selected documentation in support of the process, the staff concludes that the applicant developed and implemented adequate procedures to train personnel to implement the scoping and screening methodology described in the applicant's implementing procedures and the LRA.

2.1.3.4 Conclusion of Scoping and Screening Program Review

Based on its review of LRA Section 2.1, review of the applicant's detailed scoping and screening implementing procedures, discussions with the applicant's license renewal personnel, review of the quality controls applied to the LRA development, training of personnel participating in the LRA development, the results from the scoping and screening methodology audit, and the applicant's response to RAI 2.1-2, the staff concludes that the applicant's scoping and screening program is consistent with the SRP-LR and the requirements of 10 CFR Part 54 and, therefore, is acceptable.

2.1.4 Plant Systems, Structures, and Components Scoping Methodology

LRA Section 2.1.5, "Scoping Procedure," describes the applicant's methodology used to identify SSCs within the scope of license renewal in accordance with the requirements of the 10 CFR 54.4(a) criteria. The LRA states that the scoping process identified the SSCs that are safety-related and perform and support an intended function for responding to a design-basis event, are nonsafety-related whose failure could prevent accomplishment of a safety-related function, or perform a function that demonstrates compliance with the NRC's regulations for the following:

- fire protection (10 CFR 50.48, "Fire Protection")
- EQ (10 CFR 50.49, "Environmental Qualification of Electric Equipment Important to Safety for Nuclear Power Plants")
- pressurized thermal shock (PTS) (10 CFR 50.61, "Fracture Toughness Requirements for Protection against Pressurized Thermal Shock Events")
- anticipated transients without scram (ATWS) (10 CFR 50.62, "Requirements for the Reduction of Risk from Anticipated Transients without Scram (ATWS) Events for Light-Water-Cooled Nuclear Power Plants")
- station blackout (SBO) (10 CFR 50.63, "Loss of All Alternating Current Power")

LRA Section 2.0, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review, and Implementation Results," states that the scoping methodology used by LGS is consistent with 10 CFR Part 54 and with the industry guidance contained in NEI 95-10.

2.1.4.1 Application of the Scoping Criteria in 10 CFR 54.4(a)(1)

2.1.4.1.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(1) in LRA Section 2.1.5.1, "Safety-Related – 10 CFR 54.4(a)(1)." LRA Section 2.1.5.1 states that at LGS the safety-related plant components are identified in the CRL database and were classified using a controlled procedure, with classification criteria consistent with the 10 CFR 54.4(a)(1) criteria. The classification criteria have been evaluated in a license renewal basis document as described in LRA Section 2.1.3.2 and accounted for during the license renewal scoping process.

2.1.4.1.2 Staff Evaluation

As required by 10 CFR 54.4(a)(1), the applicant must consider all safety-related SSCs relied upon to remain functional during and following a design-basis event (DBE) to ensure the integrity of the reactor coolant pressure boundary (RCPB), the ability to shut down the reactor and maintain it in a safe shutdown condition, or the capability to prevent or mitigate the consequences of accidents that could result in potential offsite exposures comparable to those referred to in 10 CFR 50.34(a)(1), 10 CFR 50.67(b)(2), or 10 CFR 100.11, "Determination of Exclusion Area, Low Population Zone, and Population Center Distance," as applicable.

With regard to the identification of DBEs, SRP-LR Section 2.1.3, "Review Procedures," recommends that the set of DBEs as defined in the rule is not limited to Chapter 15 (or equivalent) of the UFSAR. Examples of DBEs that may not be described in this chapter of the UFSAR include external events, such as floods, storms, earthquakes, tornadoes, or hurricanes, and internal events, such as a high-energy line break (HELB). Information on DBEs, as defined in 10 CFR 50.49(b)(1), may be found in license conditions within the CLB, the NRC's regulations, NRC orders or exemptions, or any chapter of the facility UFSAR. These sources also should be reviewed to identify that they are relied upon to remain functional during and following DBEs, as defined in 10 CFR 50.49(b)(1), to ensure the functions described in 10 CFR 54.4(a)(1).

During the audit, the applicant stated that it evaluated the types of events listed in NEI 95-10 (anticipated operational occurrences, design-basis accidents (DBAs), external events, and natural phenomena) that were applicable to LGS. The staff reviewed the applicant's basis documents that describe design-basis conditions in the CLB and address events defined by 10 CFR 50.49(b)(1) and 10 CFR 54.4(a)(1). The LGS Units 1 and 2 UFSAR and basis documents discuss events such as internal and external flooding, tornados, and missiles. The staff concludes that the applicant's evaluation of DBEs was consistent with the SRP-LR.

The staff determined that the applicant performed scoping of SSCs for the 10 CFR 54.4(a)(1) criterion in accordance with the license renewal implementing procedures that provide guidance for the preparation, review, verification, and approval of the scoping evaluations to ensure the adequacy of the results of the scoping process. The staff reviewed the implementing procedures governing the applicant's evaluation of safety-related SSCs and sampled the applicant's reports of the scoping results to ensure that the applicant applied the methodology in accordance with the implementing procedures. In addition, the staff discussed the methodology and results with the applicant's personnel who were responsible for these evaluations.
The staff reviewed the applicant's evaluation of the Rule and CLB definitions pertaining to 10 CFR 54.4(a)(1) and determined that the LGS CLB definition of safety-related met the definition of safety-related specified in the Rule. The staff reviewed a sample of the license renewal scoping results for the safety-related SW system and the turbine building to provide additional assurance that the applicant adequately implemented its scoping methodology with respect to 10 CFR 54.4(a)(1). The staff confirmed that the applicant developed the scoping results for each of the sampled systems consistently with the methodology, identified the SSCs credited for performing intended functions, and adequately described the basis for the results, as well as the intended functions. The staff also confirmed that the applicant had identified and used pertinent engineering and licensing information to identify the SSCs required to be within the scope of license renewal in accordance with the 10 CFR 54.4(a)(1) criteria.

The staff noted during its review that the applicant had used the "Q" field in the CRL to identify safety-related SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(1) and that the applicant's procedure used to populate the "Q" field in the CRL refers to 10 CFR Part 100, "Reactor Site Criteria." The staff further noted during its review that LGS is an alternate source term (AST) plant such that 10 CFR 50.67, "Accident Source Term," not 10 CFR Part 100, is applicable. Therefore, the staff issued RAI 2.1-1, dated January 5, 2012, requesting the applicant to provide clarification on this apparent discrepancy.

The applicant responded to RAI 2.1-1, by letter dated January 27, 2012, and stated that the change to AST did not involve any physical changes to the plant or require any changes to the quality classification of plant components and that the design changes only involved changes to analytical methodology used for the analysis of DBAs and associated dose consequences to offsite receptors and control room personnel. The response further stated that changes to the LGS CRL after approval of the AST were reviewed, and no components were identified that require additional evaluation for license renewal; therefore, no additional scoping evaluations are required to be performed to address the 10 CFR 54.4(a)(1)(iii) criteria.

The response to RAI 2.1-1 further stated that the dose guidelines for DBAs were changed from 10 CFR 100 to 10 CFR 50.67, as described in the LGS Units 1 and 2 UFSAR, Chapter 15, as well as the description of requirements for safety-related components in LGS Units 1 and 2 UFSAR Section 3.2.3. The applicable LGS procedures also were revised to reflect this change with the exception of procedure CC-MA-304. The response also stated that an issue report has been created in the corrective action program to provide the proper reference to 10 CFR 50.67 in procedure CC-MA-304 and that this change in dose guidelines did not affect any component quality classifications and did not preclude the identification of SSCs that should have been included within the scope of license renewal in accordance with 10 CFR 54.4(a).

The staff reviewed the response to RAI 2.1-1 and determined that although the applicant's definition of safety-related referred to 10 CFR Part 100 instead of 10 CFR 50.67, the applicant's component quality classification was correct and no SSCs had been excluded from the scope of license renewal as a result. RAI 2.1-1 is resolved.

2.1.4.1.3 Conclusion

Based on its review of the LRA and the applicant's implementing procedures and reports, reviews of a system on a sampling basis, discussions with the applicant, and review of the information provided in the response to RAI 2.1-1, the staff concludes that the applicant's methodology for identifying safety-related SSCs, relied upon to remain functional during and following DBEs, and including the SSCs within the scope of license renewal, is consistent with the SRP-LR and 10 CFR 54.4(a)(1), and, therefore, is acceptable.

2.1.4.2 Application of the Scoping Criteria in 10 CFR 54.4(a)(2)

2.1.4.2.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(2).

LRA Section 1.5, "Application Structure," states that the LRA was structured in accordance with RG 1.188, "Standard Format and Content for Applications To Renew Nuclear Plant Operating Licenses," and NEI 95-10, "Industry Guideline for Implementing the Requirements of 10 CFR Part 54 – the License Renewal Rule," Revision 6.

LRA Section 2.1.5.2, "Nonsafety-Related Affecting Safety-Related – 10 CFR 54.4(a)(2)," states that the LGS Units 1 and 2 UFSAR and other CLB documents were reviewed to identify nonsafety-related systems or structures required to support satisfactory accomplishment of a safety-related function. Nonsafety-related systems or structures credited in CLB documents to support a safety-related function were included within the scope of license renewal.

For nonsafety-related piping directly connected to safety-related piping, the nonsafety-related piping was assumed to provide structural support to the safety-related piping, unless otherwise confirmed by a review of the installation details. Also, nonsafety-related piping was included in-scope for 10 CFR 54.4(a)(2), up to one of the bounding conditions described in NEI 95-10, Appendix F.

Nonsafety-related piping and components that contain water, oil, or steam, and are located inside structures that contain safety-related SSCs, were included in-scope for potential spatial interaction under 10 CFR 54.4(a)(2), unless located in an excluded room. High-energy lines located within structures that contain safety-related equipment were included in the scope of license renewal, under 10 CFR 54.4 (a)(1) or (a)(2), depending on their safety classification. Safety-related high-energy lines were included in the scope of license renewal under 10 CFR 54.4(a)(1), and nonsafety-related high-energy lines were included in the scope of license renewal under 10 CFR 54.4 (a)(2). Potential spatial interaction because of leakage or spray was assumed for system pressure as low as atmospheric. Supports for all nonsafety-related SSCs within these structures were included in the scope of license renewal.

2.1.4.2.2 Staff Evaluation

RG 1.188, Revision 1, endorses the use of NEI 95-10, Revision 6, which discusses the implementation of the staff's position on 10 CFR 54.4(a)(2) scoping criteria to include nonsafety-related SSCs that may have the potential to prevent satisfactory accomplishments of safety-related intended functions. This includes nonsafety-related SSCs connected to safety-related SSCs, nonsafety-related SSCs in proximity to safety-related SSCs, and mitigative and preventative options related to nonsafety-related and safety-related SSCs interactions. LRA Section 1.5 states that the applicant's methodology is consistent with the guidance contained in NEI 95-10, Revision 6, Appendix F.

In addition, the recommendations discussed in the SRP-LR Section 2.1.3.1.2 are that the applicant need not consider hypothetical failures, but rather should base its evaluation on the plant's CLB, engineering judgment and analyses, and relevant operating experience. NEI 95-10 further describes operating experience as all documented plant-specific and industrywide experience that can be used to determine the plausibility of a failure. Documentation would include NRC generic communications and event reports, plant-specific condition reports, industry reports, such as safety operational event reports, and engineering evaluations. The staff reviewed LRA Section 2.1.5.2 in which the applicant described the scoping methodology for nonsafety-related SSCs pursuant to 10 CFR 54.4(a)(2). In addition, the staff reviewed the applicant's implementing procedure and results report, which documented the guidance and corresponding results of the applicant's scoping review pursuant to 10 CFR 54.4(a)(2).

<u>Nonsafety-Related SSCs Required to Perform a Function that Supports a Safety-Related SSC</u>. The staff reviewed LRA Section 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure that described the method used to identify nonsafety-related SSCs, required to perform a function that supports a safety-related SSC intended function, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff confirmed that the applicant had reviewed the UFSAR, plant drawings, the CRL, and other CLB documents to identify the nonsafety-related systems and structures that function to support a safety-related system whose failure could prevent the performance of a safety-related intended function. The staff reviewed the applicant's CLB information, primarily contained in the UFSAR, related to missiles, crane load drops, flooding, and high-energy line breaks (HELBs) and determined that the applicant had included the applicable nonsafety-related SSCs within the scope of license renewal. The staff determined that the applicant's methodology for identifying and including nonsafety-related systems that perform functions that support safety-related intended functions, within the scope of license renewal, was in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs Directly Connected to Safety-Related SSCs. The staff reviewed LRA Section 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure that described the method used to identify nonsafety-related SSCs, directly connected to safety-related SSCs, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The applicant had reviewed the safety-related to nonsafety-related interfaces for each mechanical system to identify the nonsafety-related components located between the safety to nonsafety-related interface and license renewal structural boundary.

The staff determined that the applicant had used a combination of the following to identify the portion of nonsafety-related piping systems to include within the scope of license renewal:

- seismic anchors
- equivalent anchors
- bounding conditions described in NEI 95-10, Revision 6, Appendix F (base-mounted component, flexible connection, buried piping exiting the ground, inclusion to the free end of nonsafety-related piping, or inclusion of the entire piping run)

The staff determined that the applicant's methodology for identifying and including nonsafety-related SSCs, directly connected to safety-related SSCs, within the scope of license renewal was in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

Nonsafety-Related SSCs with the Potential for Spatial Interaction with Safety-Related SSCs. The staff reviewed LRA Section 2.1.5.2 and the applicant's 10 CFR 54.4(a)(2) implementing procedure that described the method used to identify nonsafety-related SSCs, with the potential for spatial interaction with safety-related SSCs, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). The staff determined that the applicant had used a spaces approach to identify the portions of nonsafety-related systems with the potential for spatial interaction with safety-related SSCs. The spaces approach focused on the interaction between nonsafety-related and safety-related SSCs that are located in the same space, which was described in the LRA as a structure containing active or passive safety-related SSCs.

The staff determined that the applicant had identified all nonsafety-related SSCs, containing liquid or steam, and located in spaces containing safety-related SSCs and included the nonsafety-related SSCs within the scope of license renewal, unless the applicant determined that the failure of a nonsafety-related SC would not result in the loss of a 10 CFR 54.4(a)(1) intended function. The staff also determined that based on plant and industry operating experience, the applicant excluded the nonsafety-related SSCs containing air or gas from the scope of license renewal, with the exception of portions attached to safety-related SSCs and required for structural support.

During its review, the staff noted that, although the LRA shows the auxiliary boiler building is in-scope in accordance with 10 CFR 54.4(a)(2), because of its proximity to the reactor enclosure and its location above the auxiliary boiler pipe tunnel (which contains safety-related pipe), the adjacent lube oil building, also located above the auxiliary boiler pipe tunnel, is not included within the scope of license renewal. Therefore, the staff requested, in RAI 2.1-3, that the applicant perform a review of this issue and provided a discussion and basis for not including the nonsafety-related lube oil building, located above the auxiliary boiler pipe tunnel, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-3, by letter dated January 27, 2012, and stated that the auxiliary boiler enclosure, auxiliary boiler pipe tunnel, fuel oil pump house enclosure, and lube oil enclosure are nonsafety-related and non-Category I structures as described within the Limerick UFSAR. The response further stated that the auxiliary boiler enclosure and the auxiliary boiler pipe tunnel are both adjacent to the safety-related seismic Category 1 reactor enclosure that is in-scope under 10 CFR 54.4(a)(1) and that the auxiliary boiler enclosure and the auxiliary boiler pipe tunnel also are in-scope under 10 CFR 54.4(a)(2) since a failure of either the auxiliary boiler enclosure or the auxiliary boiler pipe tunnel could potentially impair the integrity of the adjacent in-scope reactor enclosure. The response also stated that the nonsafety-related lube oil storage enclosure is not located immediately adjacent to a 10 CFR 54.4 (a)(1) structure and its failure would not prevent the accomplishment of any 10 CFR 54.4(a)(1) SSC intended function; therefore, the lube oil storage enclosure is not in-scope for license renewal.

The applicant's response to RAI 2.1-3 contained the revised LRA Section 2.4.3, "Auxiliary Boiler and Lube Oil Storage Enclosure," which was revised to remove the statement "and over the Auxiliary Boiler Pipe Tunnel."

The staff reviewed the applicant's response to RAI 2.1-3 and determined that the applicant had revised LRA Section 2.4.3 to clarify that the nonsafety-related auxiliary boiler enclosure is within the scope of license renewal in accordance with 10 CFR 54.4(a)(2) because it is adjacent to the reactor enclosure, which is in the scope of license renewal in accordance with 10 CFR 54.4(a)(1). The revision also removed the second reason for including the auxiliary boiler enclosure within the scope of license renewal (being over the auxiliary boiler pipe tunnel) since the auxiliary boiler pipe tunnel is a nonsafety-related structure. The staff agrees that not including the auxiliary boiler enclosure within the scope of license renewal caused by its position above the nonsafety-related auxiliary boiler pipe tunnel is appropriate. The staff determined that this rationale was also applicable to the nonsafety-related lube oil storage enclosure, which is located above the nonsafety-related auxiliary boiler pipe tunnel but is not adjacent to the reactor enclosure; therefore, it does not have the potential to affect a structure that is within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). As a result, the staff determined that the applicant had provided a basis for not including the lube oil storage enclosure within the scope of license renewal. RAI 2.1-3 is resolved.

During the scoping and screening methodology audit, the staff reviewed the license renewal application, license renewal implementing procedures, license renewal drawings, and applicable UFSAR sections. During the review of the applicant's drawing and discussions with the applicant, the staff determined that when the nonsafety-related pipe did not contain the number of supports to develop an equivalent anchor (six in total) before a branch connection in the nonsafety-related pipe attached to safety-related SCs, the applicant did not consistently identify the remaining required supports on all branch connections. Specifically, the applicant stated that in some cases the branch lines and supports are included within the scope of license renewal and in other cases are not included within the scope of license renewal. Therefore, by letter dated January 5, 2012, the staff issued RAI 2.1-4 requesting the applicant to perform a review of this issue and provide a discussion and the basis for the position of not including nonsafety-related pipe, attached to safety-related SCs, up to and including the first anchor or bounding condition, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-4, by letter dated January 27, 2012, which states, in part:

> During the audit, it was identified that in-scope nonsafety-related Unit 1, Primary Containment Instrument Gas (PCIG) system piping connected to safety-related piping did not include the required supports to develop an equivalent seismic anchor prior to a branch connection off the nonsafety-related pipe. Therefore, the license renewal 10 CFR 54.4(a)(2) boundary for the structural support intended function at the branch connection was not extended to all of the piping supports required to develop the equivalent anchor. Further review of this piping configuration identified that the license renewal 10 CFR 54.4(a)(2) boundary needed to be extended to include several feet of additional piping and associated piping supports. This change does not result in additional function/component/material combinations within the aging management review for the PCIG system as shown in LRA Table 3.3.2-14.
>
> The methodology used for the determination of safety-related/nonsafety-related interfaces is described in LRA Section 2.1.5.2. For nonsafety-related piping directly connected to safety-related piping, the nonsafety-related piping was assumed to provide structural support to the safety-related piping, and is included within the scope of license renewal for 10 CFR 54.4(a)(2). An extent of condition review performed for all systems within the scope of license renewal identified six additional instances within the scoping performed for the LRA, where the 10 CFR 54.4(a)(2) boundary at a branch connection was not extended to all of the piping supports required to develop an equivalent seismic anchor or bounding criteria described in NEI 95-10, Appendix F. All of the locations are within the PCIG system. Extension of the 10 CFR 54.4(a)(2) boundary at these branch connections results in adding nine valve bodies and several sections of piping and piping components within the scope of license renewal. The review also identified the need to add two function/component/material combinations to the aging management review for the PCIG system.

The staff reviewed the response to RAI 2.1-4 and determined that the applicant had reviewed the method and its implementation used to identify the portions of nonsafety-related pipe (attached to safety-related pipe) and supports required to establish an equivalent anchor, when the nonsafety-related pipe included branch connections. The applicant also stated that, following its review, it found that it had not consistently evaluated nonsafety-related pipe containing branch connections. This review resulted in the applicant identifying and including additional portions of nonsafety-related pipe and supports within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). On the basis of these actions, RAI 2.1-4 is resolved.

During the scoping and screening methodology audit, the staff reviewed the applicant's implementing procedure that describes the process used to identify nonsafety-related SSCs, whose failure could potentially affect the performance of the intended function of safety-related SSCs, for inclusion within the scope of license renewal. The staff determined that the applicant's implementing procedure, when discussing nonsafety-related pipe directly attached to safety-related SCs, does not require that a portion of the nonsafety-related pipe (and applicable anchors or bounding conditions on the nonsafety-related side of the interface) to be included within the scope of license renewal. Instead, the implementing procedure allows for an anchor directly at the nonsafety-related/safety-related interface, or close to the interface (on the safety-related side of the interface) to be used as the last anchor within the scope of license renewal. Therefore, the staff issued RAI 2.1-5, by letter dated January 5, 2012, requesting the applicant to perform a review of this issue and provide a discussion and basis for the use of an implementing procedure that does not require including nonsafety-related pipe, attached to safety-related SCs, up to and including the first anchor or bounding condition, beyond the nonsafety-related/safety-related interface, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-5, by letter dated January 27, 2012, which states, in part:

> The methodology used for the determination of safety-related to nonsafety-related interfaces is described in LRA Section 2.1.5.2. For nonsafety-related piping directly connected to safety-related piping, the nonsafety-related piping was assumed to provide structural support to the safety-related piping, and is included within the scope of license renewal for 10 CFR 54.4(a)(2) up to and including the first anchor or bounding condition past the safety-related to nonsafety-related interface. The procedure for scoping and the scoping basis document for the determination of 10 CFR 54.4(a)(2) SSCs are consistent with this methodology. The procedure for the development of license renewal boundary drawings is not consistent with this methodology. This procedure provides several examples of drawing notes where the credited anchor is located on the safety-related piping and the nonsafety-related attached piping beyond the safety-related to nonsafety-related interface is not included in-scope for structural support.
>
> An extent of condition review, performed for all systems within the scope of license renewal, determined that there are no instances within the scoping performed for the preparation of the LRA, where an anchor or bounding condition on safety-related piping was credited for determining the license renewal boundary for piping that has a safety-related to nonsafety-related interface. Therefore, the review concluded that use of the scoping methodology as described in the procedure for the development of license renewal boundary drawings did not preclude the identification of systems, structures, and components (SSCs) which should have been included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). No additional scoping evaluations are required to address the 10 CFR 54.4(a)(2) criteria and there are no additional SSCs to be included within the license renewal scope as a result of this review.

The staff reviewed the response to RAI 2.1-5 and determined that although the applicant's procedure for developing the license renewal boundary drawings provides several examples of drawing notes in which the credited anchor is located on the safety-related piping, and the nonsafety-related attached piping beyond the safety-related to nonsafety-related interface is not included in-scope for structural support. This approach is not in agreement with the method described in the LRA or the applicant's 10 CFR 54.4(a)(2) implementing procedure. The staff determined that the applicant had performed a review of all nonsafety-related pipe attached to safety-related pipe and confirmed that, in all cases, an appropriate portion of nonsafety-related pipe and support beyond the safety-related nonsafety-related interface was included within the scope of license renewal in accordance with the method described in the LRA and the 10 CFR 54.4(a)(2) implementing procedure, and that the method described in the license renewal boundary drawing procedure had not been used. The staff determined that this met the requirements of 10 CFR 54.4(a)(2). RAI 2.1-5 is resolved.

During the scoping and screening methodology audit the applicant stated that if the first anchor or bounding condition was determined to be beyond the area of potential spatial interaction for spray or leakage within the structure or room (space), the portion of nonsafety-related pipe, attached to a safety-related SC, included within the scope of license renewal was continued outside the space, up to and including an anchor or bounding condition identified on the boundary drawing. However, the applicant stated that if the anchor or bounding condition was within the space, the applicant included the pipe up to the boundary of the space, but did not specifically identify the anchor or bounding condition on the boundary drawing. The staff was not able to determine the process the applicant used to confirm that an anchor or bounding condition existed within a space, if an anchor or bounding condition was not specifically identified. Therefore, the staff issued RAI 2.1-6, by letter dated January 5, 2012, requesting the applicant to perform a review of this issue and provide a discussion on the process used to verify that an anchor or bounding condition exists within the area of potential spatial interaction or nonsafety-related pipe attached to safety-related SCs, and, therefore, no additional pipe, anchors or bounding conditions needed to be included within the scope of license renewal outside the area of potential spatial interaction.

The applicant responded to RAI 2.1-6, by letter dated January 27, 2012, which states, in part:

> The methodology for evaluating nonsafety-related SSCs affecting safety-related SSCs is described in LRA Section 2.1.5.2. For nonsafety-related piping directly connected to safety-related piping, the nonsafety-related piping was assumed to provide structural support to the safety-related piping. The nonsafety-related piping was included in-scope for 10 CFR 54.4(a)(2) up to an anchor or bounding condition. Failure in the nonsafety-related piping beyond this boundary would not impact structural support for the safety-related piping. If the connected nonsafety-related piping system contains fluid, then the in-scope boundary was extended beyond the anchor or bounding condition caused by the potential for spatial interaction out to a point where there is no longer a spatial relationship. LRA Table 2.1-1 defines the Leakage Boundary intended function. Nonsafety-related components required to maintain mechanical and structural integrity to prevent spatial interactions that could cause failure of safety-related SSCs have a Leakage Boundary intended function. This function includes the required structural support when the nonsafety-related piping is also attached to safety-related piping.
>
> The Leakage Boundary intended function is shown on the license renewal drawings in red. When the SSCs, in-scope for structural support, are enveloped by the SSCs in-scope for spatial interaction, the location of the structural support endpoint has not been identified on the license renewal boundary drawing. When the location of the structural endpoint extends past the spatial envelope, the intended function of Structural Support is applied and a note is added to the license renewal boundary drawing.
>
> An extent of condition review was performed on all license renewal boundary drawings associated with all systems within the scope of license renewal to identify the seismic anchors or bounding conditions within the areas of potential spatial interaction. This review confirmed that the scoping methodology was correctly implemented and that the seismic anchors or bounding conditions were within the

areas of potential spatial interaction as shown on the license renewal boundary drawings except as described below. As a result of this review, the following (a)(2) structural support boundaries needed to be extended beyond the spatial envelope to include a seismic anchor or boundary condition.

The applicant's response to RAI 2.1-6 provided a summary of the structural support boundaries required to extend beyond the spatial envelope to include a seismic anchor or boundary condition, which included the following:

- Condensate system – The (a)(2) scoping boundary for the 10-inch HBC-108 stainless steel piping was incorrectly identified at the Unit 1, Reactor Enclosure wall on [the applicable] license renewal boundary. The scoping boundary should have extended through the wall beyond the spatial envelope to just inside the Radwaste Enclosure to the credited anchor. This additional piping is in-scope with a structural support intended function only since leakage is not a concern within the Radwaste Enclosure because the Radwaste Enclosure does not house safety-related SSCs.
- Safety-related service water system – The (a)(2) scoping boundary for 3-inch HBD carbon steel piping associated with the Unit 1 residual heat removal (RHR) heat exchanger tube corrosion monitoring subsystem was identified incorrectly on [the applicable] license renewal boundary drawing. The scoping boundary should have extended up to and included the base mounted specimen chamber and specimen chamber service water pump. The piping, specimen chamber, and specimen chamber service water pump are added to license renewal scope only for structural support intended function, since this equipment is abandoned, has been confirmed to be drained, and does not create a spatial interaction concern.

The staff reviewed the response to RAI 2.1-6 and determined that the information contained in the LRA and the applicant's 10 CFR 54.4(a)(2) implementing procedure, related to nonsafety-related piping directly connected to safety-related piping, specifically when a portion of the nonsafety-related pipe was also included within the scope of license renewal because of the potential for spatial interaction with safety-related SSCs, was in accordance with the requirements of 10 CFR 54.4(a)(2). The staff determined that the applicant had confirmed that the method documented in the LRA and the 10 CFR 54.4(a)(2) implementing procedure was correct and performed an extent of condition review to confirm that the method described in the LRA and the 10 CFR 54.4(a)(2) procedure had been applied. The applicant performed an extent of condition review and determined that to be in accordance with the method described in the LRA and the 10 CFR 54.4(a)(2) implementing procedure, two boundaries were required to be extended beyond the area of potential spatial interaction with safety-related SSCs to include additional nonsafety-related pipe and supports within the scope of license renewal. The staff determined that this met the requirements of 10 CFR 54.4(a)(2). RAI 2.1-6 is resolved.

During the scoping and screening methodology audit, the staff noted that the applicant identified containment boundaries in the scope of license renewal, including the ceiling of the suppression pool. The staff also noted that there is abandoned nonsafety-related structural and miscellaneous steel (including the Q-deck) attached to the safety-related diaphragm slab. The applicant had determined not to include the abandoned nonsafety-related structural and miscellaneous steel within the scope of license renewal. Therefore, the staff issued RAI 2.1-7, by letter dated January 5, 2012, requesting the applicant to perform a review of this issue and provide a discussion and basis for the position of not including abandoned nonsafety-related structural and miscellaneous steel, attached to safety-related structures, within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).

The applicant responded to RAI 2.1-7, by letter dated January 27, 2012, which states, in part:

> Miscellaneous steel is included in LRA Table 2.4-11 as a component type within the scope of license renewal and subject to aging management review. LGS LRA Section 2.4.11, Primary Containment, page 2.4-46 states: "The Containment Structure performs intended functions delineated in 10 CFR 54.4 and is in-scope for license renewal in its entirety, except for the metal decking and abandoned steel under the diaphragm slab, which does not perform an intended function." The design documents show that the subject metal decking serves no structural purpose and was designed as a form to support placement of concrete during construction. The metal decking is supported by structural steel, which is within the scope of license renewal in accordance with 10 CFR 54.4 (a)(1) and 10 CFR 54.4(a)(2). The abandoned steel shown on a drawing for the diaphragm slab is limited to an abandoned monorail, which is supported by other structural steel and bolting, which are within the scope of license renewal in accordance with 10 CFR 54.4 (a)(1) and 10 CFR 54.4(a)(2). The metal decking and abandoned monorail steel under the diaphragm slab do not perform any intended function and they are supported by structural steel and bolting, which is within the scope of license renewal in accordance with 10 CFR 54.4 (a)(1) and 10 CFR 54.4(a)(2). The decision to not include the metal decking and abandoned monorail steel under the diaphragm slab within the scope of license renewal is consistent with the methodology discussed in Section 2.1.3.3 of the LRA. This is also consistent with the industry guidelines as described within NEI 95-10 Appendix F and as applied to other items such as nonsafety-related air and gas system piping and components, where the piping is not in-scope but whose supports are in-scope. A review of this issue was performed and it was concluded that the scoping methodology correctly identified the systems, structures, and components (SSCs), which should be included within the scope of license renewal in accordance with 10 CFR 54.4(a)(2).
>
> However, the metal decking on the underside of the Primary Containment diaphragm slab has been visually examined during the Containment ISI IWL examinations of the underside of the concrete diaphragm slab. The decking is now included within the scope of license renewal, as component type "Metal Decking" and subject to aging management using the Structures Monitoring aging management program during the inspections of the adjacent support steel. In addition, since the abandoned monorail steel is the only abandoned steel beneath the diaphragm slab and represents a small fraction of the steel under the diaphragm slab, the remainder of which is in-scope, the abandoned monorail steel is now included in-scope for completeness, as component type "Metal Components: All structural members (includes abandoned monorail steel)" and is subject to the Structures Monitoring aging management program.

The staff reviewed the response to RAI 2.1-7 and determined that that applicant had reviewed the scoping evaluation of the abandoned steel in containment, which included metal decking and abandoned monorail steel under the diaphragm slab, and subsequently included the abandoned steel within the scope of license renewal in accordance with 10 CFR 54.4(a)(2). RAI 2.1-7 is resolved.

The staff determined that the applicant's methodology for identifying and including nonsafety-related SSCs, with the potential for spatial interaction with safety-related SSCs, within the scope of license renewal was in accordance with the guidance of the SRP-LR and the requirements of 10 CFR 54.4(a)(2).

2.1.4.2.3 Conclusion

Based on its review of the LRA and the applicant's implementing procedures and reports, selected system reviews and walkdowns, discussions with the applicant, and review of the information provided in the response to RAIs 2.1-3, 2.1-4, 2.1-5, 2.1-6 and 2.1-7, the staff concludes that the applicant's methodology for identifying and including nonsafety-related SSCs, whose failure could prevent satisfactory accomplishment of the intended functions of safety-related SSCs, within the scope of license renewal, is in accordance with the requirements 10 CFR 54.4(a)(2), and, therefore, is acceptable.

2.1.4.3 Application of the Scoping Criteria in 10 CFR 54.4(a)(3)

2.1.4.3.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(3).

LRA Section 2.1.3.4, "Scoping for Regulated Events," states that the technical basis documents were prepared to address license renewal scoping of SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection, EQ, ATWS, and SBO, and that the NRC's regulations for pressurized thermal shock are not applicable to the LGS boiling-water reactor (BWR) design.

LRA Section 2.1.5.3, "Regulated Events – 10 CFR 54.4(a)(3)," states that for each of the four applicable regulations, a technical basis document was prepared to provide input into the scoping process. Each of the regulated event technical basis documents, described in LRA Section 2.1.3.4, identifies the systems and structures relied upon to demonstrate compliance with the applicable regulation. The technical basis documents also identify the source documentation used to determine the scope of components within the system credited to demonstrate compliance with each of the applicable regulated events.

The LRA states that the guidance provided by the technical basis documents were incorporated into the system and structure scoping evaluations to determine the SSCs credited for each of the four applicable regulations. SSCs credited in the four applicable regulations have been classified as satisfying 10 CFR 54.4(a)(3) criteria and have been included within the scope of license renewal.

2.1.4.3.2 Staff Evaluation

The staff reviewed LRA Sections 2.1.3.4 and 2.1.5.3 that described the method used to identify, and include within the scope of license renewal, those SSCs relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection, EQ, ATWS, and SBO. As part of this review, during the scoping and screening methodology audit, the staff had discussions with the applicant, reviewed implementing procedures and the technical basis documents, license renewal drawings, and scoping results reports. The staff determined that the applicant had evaluated the CLB to identify SSCs that perform functions addressed in 10 CFR 54.4(a)(3), and included these SSCs within the scope of license renewal as documented in the scoping reports. In addition, the staff determined that the scoping report results referenced the information sources used for determining the SSCs credited for compliance with the events.

Fire Protection. The staff reviewed the applicant's implementing procedure and technical basis document that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (fire protection – 10 CFR 50.48). The implementing procedure described a process that considered CLB information, including the UFSAR and the fire protection technical basis document. The staff reviewed applicable portions of the LRA, CLB information, and license renewal drawings to verify that the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the fire protection technical basis document.

Based on its review of the CLB documents and the sample review, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in allowing functions that perform fire protection within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(3).

Environmental Qualification (EQ). The staff reviewed the applicant's implementing procedure and technical basis document that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (EQ – 10 CFR 50.49). The implementing procedure described a process that considered CLB information, including the UFSAR and the EQ technical basis document. The staff reviewed applicable portions of the LRA, CLB information, LGS EQ program documentation, and license renewal drawings to verify that the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the EQ technical basis document. Based on its review of the CLB documents and the sample review, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing EQ functions within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(3).

Anticipated Transient Without Scram (ATWS). The staff reviewed the applicant's implementing procedure and technical basis document that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (ATWS – 10 CFR 50.62). The implementing procedure described a process that considered CLB information, including the UFSAR and the ATWS technical basis document. The staff reviewed portions of the applicable portions of LRA, CLB information, and license renewal drawings to verify that the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the

ATWS technical basis document. Based on its review of the CLB documents and the sample review of scoping reports, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing ATWS functions within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(3).

Station Blackout (SBO). The staff reviewed the applicant's implementing procedure and technical basis document that described the method used to identify SSCs within the scope of license renewal in accordance with 10 CFR 54.4(a)(3) (SBO – 10 CFR 50.63). The implementing procedure described a process that considered CLB information, including the UFSAR and the SBO technical basis document. The staff reviewed applicable portions of the LRA, CLB information, applicable portions of the UFSAR, commitments and analyses that demonstrate compliance with 10 CFR 50.63, and license renewal drawings to verify that the appropriate SSCs were included within the scope of license renewal. In addition, the staff reviewed a selected sample of scoping reports for the systems and structures identified in the SBO technical basis document. Based on its review of the CLB documents and the sample review of scoping reports, the staff determined that the applicant's methodology was adequate for identifying and including SSCs credited in performing SBO functions within the scope of license renewal, in accordance with the requirements of 10 CFR 54.4(a)(3).

Pressurized Thermal Shock (PTS). Regulations in 10 CFR 54.4(3) state that SSCs relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations, include, among others, PTS (10 CFR 50.61) are within the scope of license renewal. The regulation contained in 10 CFR 50.61 only applies to pressurized-water reactor (PWR) type reactors and, therefore, are not applicable to LGS Units 1 and 2.

2.1.4.3.3 Conclusion

Based on its review of the LRA and the applicant's implementing procedures and reports, reviews of systems on a sampling basis, and discussions with the applicant, the staff concludes that the applicant's methodology for identifying and including SSCs, relied upon to remain functional during regulated events, is consistent with the SRP-LR and 10 CFR 54.4(a)(3) and, therefore, is acceptable.

2.1.4.4 Plant-Level Scoping of Systems and Structures

2.1.4.4.1 Summary of Technical Information in the Application

The applicant described the methods used to identify SSCs included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a) in LRA Section 2.1.1. The LRA states that the initial step in the scoping process was to define the entire plant in terms of systems and structures. These systems and structures were evaluated against the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3) to determine if they perform or support a safety-related intended function, perform functions that demonstrate compliance with the requirement of one of the five regulations described in 10 CFR 54.4(a)(3), provide structural support for safety-related SSCs, or have the potential for spatial interactions with safety-related SSCs. For the systems and structures determined to be within the scope of license renewal, the intended functions that are the bases for including them within the scope of license renewal also were identified.

The LRA further stated that if any portion of a system or structure met the scoping criteria of 10 CFR 54.4, the system or structure was included in the scope of license renewal. Mechanical systems and structures were then further evaluated to determine those mechanical and structural components that perform or support the identified intended functions.

2.1.4.4.2 Staff Evaluation

The staff reviewed the applicant's methodology for identifying SSCs within the scope of license renewal to verify it met the requirements of 10 CFR 54.4. The applicant had developed implementing procedures that described the processes used to identify the systems and structures subject to 10 CFR 54.4 review and to determine if the system or structure performed intended functions consistent with the criteria of 10 CFR 54.4(a) and to document the activities in scoping results reports. The process defined the plant in terms of systems and structures and was completed for all systems and structures onsite to ensure that the entire plant was assessed.

The staff determined that the applicant had identified the SSCs within the scope of license renewal and documented the results of the scoping process in reports in accordance with the implementing procedures. The reports included a description of the structure or system, a listing of functions performed by the system or structure, identification of intended functions, the 10 CFR 54.4(a) scoping criteria met by the system or structure, references, and the basis for the classification of the system or structure intended functions. During the audit, the staff reviewed a sampling of the implementing documents and reports and determined that the applicant's scoping results contained an appropriate level of detail to document the scoping process.

2.1.4.4.3 Conclusion

Based on its review of the LRA, implementing procedures, and a sampling of system scoping results reviewed during the audit, the staff concludes that the applicant's methodology for identifying systems and structures within the scope of license renewal, and their intended functions, is consistent with the requirements of 10 CFR 54.4 and, therefore, acceptable.

2.1.4.5 Mechanical Component Scoping

2.1.4.5.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify mechanical SSCs within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a).

LRA Section 2.1.1 states that the in-scope boundaries of mechanical systems and structures were developed and are described in LRA Sections 2.3 and 2.4. These boundaries also are depicted on the license renewal boundary drawings.

LRA Section 2.1.5.5 "Scoping Boundary Determination – Mechanical Systems," states that for mechanical systems, the mechanical components that support the system-intended functions were included in the scope of license renewal and are depicted on the applicable system piping and instrumentation diagram. Mechanical system piping and instrumentation diagrams are marked up to create license renewal boundary drawings showing the components within the scope of license renewal. Components required to support a safety-related function, or a function that demonstrates compliance with one of the five regulations described in

10 CFR 54.4(a)(3), are identified on the system piping and instrumentation diagrams by green highlighting. Nonsafety-related components connected to safety-related components and that are required to provide structural support at the safety/nonsafety interface, or components whose failure could prevent satisfactory accomplishment of a safety-related function because of spatial interaction with safety-related SSCs, are identified by red highlighting. A computer sort and download of associated system components from the CRL database confirms the scope of components in the system. Plant walkdowns were performed when required for additional confirmation.

2.1.4.5.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.1 and 2.1.5.5, implementing procedures, reports, and the CLB source information associated with mechanical scoping. The staff determined that the CLB source information and implementing procedures' guidance the applicant used was acceptable to identify mechanical SSCs within the scope of license renewal. The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant had appropriately applied the scoping methodology outlined in the LRA and the implementing procedures and whether the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was consistent with the description provided in the LRA Sections 2.1.1 and 2.1.5.5 and the guidance contained in the SRP-LR, Section 2.1, and was adequately implemented.

On a sampling basis, the staff reviewed the applicant's scoping reports for the safety-related SW system and the process used to identify mechanical components that met the scoping criteria of 10 CFR 54.4. The staff reviewed the implementing procedures, confirmed that the applicant had identified and used pertinent engineering and licensing information, and discussed the methodology and results with the applicant. As part of the review process, the staff evaluated the system's identified intended functions and the process used to identify system component types. The staff confirmed that the applicant had identified and highlighted license renewal drawings to identify the license renewal boundaries in accordance with the implementing procedure guidance. Additionally, the staff determined that the applicant had independently confirmed the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results had performed independent reviews of the scoping reports and applicable license renewal drawings to ensure accurate identification of the system intended functions. The staff confirmed that the systems and components identified by the applicant were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff confirmed that the applicant had used pertinent engineering and licensing information to determine that systems and components were included within the scope of license renewal, in accordance with the 10 CFR 54.4(a).

2.1.4.5.3 Conclusion

Based on its review of the LRA, scoping implementing procedures, and the sampling system review of mechanical scoping results, the staff concludes that the applicant's methodology for identifying mechanical SSCs within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, acceptable.

2.1.4.6 Structural Component Scoping

2.1.4.6.1 Summary of Technical Information in the Application

LRA Section 2.1.5.5 "Scoping Boundary Determination – Structures," states that for structures, the structural components that support the intended functions are included in the scope of license renewal. The structural components are identified from a review of applicable plant design drawings of the structure. Plant walkdowns were performed when required for additional confirmation. A single site plan layout drawing is marked up to create a license renewal boundary drawing showing the in-scope structures.

2.1.4.6.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.1 and 2.1.5.5, implementing procedures, reports, and the CLB source information associated with structural scoping. The staff determined that the CLB source information and implementing procedures' guidance the applicant used was acceptable to identify structural SSCs within the scope of license renewal. The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant had appropriately applied the scoping methodology outlined in the LRA and the implementing procedures, and whether the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was consistent with the description provided in the LRA Sections 2.1.1 and 2.1.5.5 and the guidance contained in the SRP-LR, Section 2.1 and was adequately implemented.

On a sampling basis, the staff reviewed the applicant's scoping reports for the turbine building and the process used to identify structural systems and components that met the scoping criteria of 10 CFR 54.4. The staff reviewed the implementing procedures, confirmed that the applicant had identified and used pertinent engineering and licensing information, and discussed the methodology and results with the applicant. As part of the review process, the staff evaluated the turbine building's identified intended functions and the process used to identify structural component types. Additionally, the staff determined that the applicant had confirmed the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results had performed independent reviews of the scoping reports and the applicable license renewal drawings to ensure accurate identification of the system intended functions. The staff confirmed that the structures and components identified by the applicant were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff confirmed that the applicant had used pertinent engineering and licensing information to determine that systems and components were included within the scope of license renewal in accordance with the 10 CFR 54.4(a).

2.1.4.6.3 Conclusion

Based on its review of information in the LRA, the scoping implementation procedure, and review of structural scoping results, the staff concludes that the applicant's methodology for identification of the structures and structural components within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4 and, therefore, acceptable.

2.1.4.7 Electrical Component Scoping

2.1.4.7.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SSCs included within the scope of license renewal in accordance with the requirements of 10 CFR 54.4(a).

LRA Section 2.1.1 states that electrical and instrumentation and control (I&C) systems were scoped like mechanical systems and structures per the scoping criteria in 10 CFR 54.4(a)(1), (a)(2), and (a)(3). Electrical and I&C components within electrical and I&C systems that are within the scope of license renewal were included in the scope of license renewal. Likewise, electrical and I&C components in mechanical systems within the scope of license renewal were included in the scope of license renewal. Consequently, further system evaluations to determine which electrical components were required to perform or support the system intended functions were not performed during the scoping process.

LRA Section 2.1.5.5 "Scoping Boundary Determination – Electrical and I&C Systems," states that electrical and I&C systems, and electrical components within mechanical systems, did not require further system evaluations to determine which components were required to perform or support the identified intended functions. A bounding scoping approach was used for electrical equipment. All electrical components in systems within the scope of license renewal were included in the scope of license renewal. Electrical components within the scope of license renewal were placed into commodity groups and evaluated as commodities during the screening process as described in LRA Section 2.1.6.

2.1.4.7.2 Staff Evaluation

The staff evaluated LRA Sections 2.1.1 and 2.1.5.5, implementing procedures, reports, and the CLB source information associated with electrical scoping. The staff determined that the CLB source information and implementing procedures' guidance the applicant used was acceptable to identify electrical SSCs within the scope of license renewal. The staff conducted detailed discussions with the applicant's license renewal project personnel and reviewed documentation pertinent to the scoping process during the scoping and screening methodology audit. The staff assessed whether the applicant had appropriately applied the scoping methodology outlined in the LRA and the implementing procedures, and whether the scoping results were consistent with CLB requirements. The staff determined that the applicant's procedure was consistent with the description provided in the LRA Sections 2.1.1 and 2.1.5.5 and the guidance contained in the SRP-LR, Section 2.1, and was adequately implemented.

The staff noted that after the scoping of electrical and I&C components was performed, the electrical components within the scope of license renewal were categorized into electrical commodity groups. Commodity groups include electrical and I&C components with common characteristics. Component-level intended functions of the component types were identified. The electrical commodities included cable connections, fuse holders, high-voltage insulators, insulation material for electrical cables and connections, metal enclosed bus (MEB), switchyard bus and connections, and transmission conductors and connectors.

As part of this review, the staff discussed the methodology with the applicant, reviewed the implementing procedures developed to support the review, and evaluated the scoping results for a sample of SSCs identified within the scope of license renewal. The staff reviewed the implementing procedures, confirmed that the applicant had identified and used pertinent engineering and licensing information, and discussed the methodology and results with the applicant. Additionally, the staff determined that the applicant had independently confirmed the results in accordance with the implementing procedures. The staff confirmed that the applicant's license renewal personnel verifying the results had performed independent reviews of the scoping reports and the applicable license renewal drawings to ensure accurate identification of the system intended functions. The staff confirmed that the electrical SSCs the applicant identified were evaluated against the criteria of 10 CFR 54.4(a)(1), (a)(2), and (a)(3). The staff determined that the applicant scoping included appropriate electrical and I&C components as well as electrical and I&C components contained in mechanical or structural systems within the scope of license renewal on a commodity basis, in accordance with 10 CFR 54.4(a).

2.1.4.7.3 Conclusion

Based on its review of information contained in the LRA, scoping implementing procedures, and a sampling review of electrical scoping results, the staff concludes that the applicant's methodology for identifying electrical components within the scope of license renewal is in accordance with the requirements of 10 CFR 54.4, and therefore, acceptable.

2.1.4.8 Conclusion for Scoping Methodology

Based on its review of the LRA, implementing procedures, and a sampling review of scoping results, the staff concludes that the applicant's scoping methodology was consistent with the guidance contained in the SRP-LR and identified those SSCs that are safety-related, whose failure could affect safety-related intended functions, and that are necessary to demonstrate compliance with the NRC's regulations for fire protection, EQ, ATWS, and SBO. The staff concluded that the applicant's methodology is consistent with the requirements of 10 CFR 54.4(a), and, therefore, is acceptable.

2.1.5 Screening Methodology

2.1.5.1 General Screening Methodology

After identifying systems and structures within the scope of license renewal, the applicant implemented a process for identifying SCs subject to an AMR, in accordance with 10 CFR 54.21.

2.1.5.1.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1, "Identification of Structures and Components Subject to an AMR," states that SCs that perform an intended function without moving parts or without a change in configuration or properties are defined as passive for license renewal. Passive structures and components that are not subject to replacement based on a qualified life or specified time period are defined as long-lived for license renewal. The screening procedure is the process used to identify the passive, long-lived structures and components in the scope of license renewal that are subject to an AMR.
NUREG-1800, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" and NEI 95-10, Appendix B, were used as the basis for identifying passive structures and components. Most passive structures and components are long-lived. In the few cases in which a passive component was determined not to be long-lived, such determination was documented in the screening evaluation and, if applicable, on the associated license renewal boundary drawing.

2.1.5.1.2 Staff Evaluation

As required by 10 CFR 54.21, each LRA must contain an IPA that identifies SCs within the scope of license renewal and that are subject to an AMR. The IPA must identify components that perform an intended function without moving parts or a change in configuration or properties (passive), as well as components that are not subject to periodic replacement based on a qualified life or specified time period (long-lived). In addition, the IPA must include a description and justification of the methodology used to identify passive and long-lived SCs, and a demonstration that the effects of aging on those SCs will be adequately managed so that the intended function(s) will be maintained under all design conditions imposed by the plant-specific CLB for the period of extended operation.

The staff reviewed the methodology the applicant used to identify the mechanical, structural, and electrical SSCs within the scope of license renewal that are subject to an AMR. The applicant implemented a process for determining which SCs were subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1). The staff determined that the screening process evaluated the component types and commodity groups, included within the scope of license renewal, to determine which ones were long-lived and passive and, therefore, subject to an AMR. The staff reviewed on a sampling basis the screening results reports for the safety-related SW system and the turbine building. The applicant provided the staff with a detailed discussion of the processes used for each discipline and provided administrative documentation that described the screening methodology. Specific screening methodology for mechanical, structural, and electrical SCs is discussed in SER Sections 2.1.5.2, 2.1.5.3, and 2.1.5.4.

2.1.5.1.3 Conclusion

Based on its review of the LRA, the implementing procedures and a sampling of screening results, the staff concludes that the applicant's screening methodology was consistent with the guidance contained in the SRP-LR and was capable of identifying passive, long-lived components, within the scope of license renewal, which are subject to an AMR. The staff concludes that the applicant's process for determining the SCs subject to an AMR is consistent with the requirements of 10 CFR 54.21 and is, therefore, acceptable.

2.1.5.2 Mechanical Component Screening

2.1.5.2.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify mechanical SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1, "Identification of Structures and Components Subject to an AMR – Mechanical Systems," states that for mechanical systems within the scope of license renewal, the completed scoping packages include written descriptions and marked-up system piping and instrumentation diagrams that clearly identify the in-scope system boundary for license renewal. The marked-up system piping and instrumentation diagrams are called boundary drawings for license renewal. These system boundary drawings were reviewed to identify the passive, long-lived components, and the identified components then were entered into the license renewal database. Component listings from the CRL database also were reviewed to confirm that all system components were considered. In cases in which the system piping and instrumentation diagram did not provide sufficient detail (e.g., some large vendor-supplied components), the associated component drawings or vendor manuals also were reviewed. Plant walkdowns were performed when required for confirmation. The identified list of passive, long-lived system components was benchmarked against previous license renewal applications containing a similar system.

2.1.5.2.2 Staff Evaluation

The staff reviewed the applicant's methodology used for mechanical component screening as described in LRA Section 2.1.6.1, implementing procedures, basis documents, and the mechanical scoping and screening reports. The staff confirmed that the applicant used the screening process described in these documents along with the information contained in NEI 95-10, Appendix B, and the SRP-LR to identify the mechanical SCs subject to an AMR.

The staff determined that the applicant had identified SCs that met the passive criteria in accordance with the guidance contained in NEI 95-10. In addition, the staff determined that the applicant had evaluated the identified passive commodities to determine that they were not subject to replacement, based on a qualified life or specified time period (long-lived), and that the remaining passive, long-lived components were subject to an AMR.

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. During the scoping and screening methodology audit, the staff reviewed the safety-related SW system screening report and discussed the report with the applicant and confirmed proper implementation of the screening process.

2.1.5.2.3 Conclusion

Based on its review of information contained in the LRA, implementing procedures, and the sampled mechanical screening results, the staff concludes that the applicant's methodology for identification of mechanical SCs within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, acceptable.

2.1.5.3 Structural Component Screening

2.1.5.3.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify structural SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1, "Identification of Structures and Components Subject to an AMR – Containments, Structures, and Component Supports," states that for structures within the scope of license renewal, the completed scoping packages include written descriptions of the structure. If only selected portions of the structure are within the scope of license renewal, the portions within the scope of license renewal are described in the scoping evaluation. The associated structure drawings were reviewed to identify the passive, long-lived SCs, and the identified SCs then were entered into the license renewal database. Component listings from the CRL database were also reviewed to confirm that all structural components were considered. Plant walkdowns were performed when required for confirmation. The identified list of passive, long-lived structures and components was benchmarked against previous license renewal applications.

2.1.5.3.2 Staff Evaluation

The staff reviewed the applicant's methodology used for structural component screening as described in LRA Section 2.1.6.1, implementing procedures, basis documents, and the structural scoping and screening reports. The staff confirmed that the applicant used the screening process described in these documents along with the information contained in NEI 95-10, Appendix B, and the SRP-LR to identify the structural SCs subject to an AMR.

The staff determined that the applicant had identified structural SCs that met the passive criteria in accordance with NEI 95-10. In addition, the staff determined that the applicant evaluated the identified passive commodities to determine that they were long-lived and that the remaining passive, long-lived components were determined to be subject to an AMR.

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. During the scoping and screening methodology audit, the staff reviewed the turbine building screening report and discussed the report with the applicant and confirmed proper implementation of the screening process.

2.1.5.3.3 Conclusion

Based on its review of information contained in the LRA, implementing procedures, and the sampled structural screening results, the staff concludes that the applicant's methodology to identify structural SCs within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, acceptable.

2.1.5.4 Electrical Component Screening

2.1.5.4.1 Summary of Technical Information in the Application

The applicant addressed the methods used to identify electrical SCs included within the scope of license renewal that are subject to an AMR in accordance with the requirements of 10 CFR 54.21. LRA Section 2.1.6.1, "Identification of Structures and Components Subject to an AMR – Electrical and I&C Commodities," states that screening of electrical and I&C commodities within the electrical, I&C, and mechanical systems within the scope of license renewal used a bounding approach as described in NEI 95-10. Electrical and I&C components for the systems within the scope of license renewal were assigned to commodity groups. The commodities subject to an AMR were identified by applying the criteria of 10 CFR 54.21(a)(1). This method provided the most efficient way to determine the electrical commodities subject to an AMR, since many electrical and I&C components and commodities are active and, therefore, not subject to an AMR.

2.1.5.4.2 Staff Evaluation

The staff reviewed the applicant's methodology used for electrical component screening as described in LRA Section 2.1.6.1, implementing procedures, basis documents, and the electrical scoping and screening reports. The staff confirmed that the applicant had used the screening process described in these documents along with the information contained in NEI 95-10, Appendix B, and the SRP-LR to identify the electrical SSCs subject to an AMR.

The staff determined that the applicant had identified electrical commodity groups that met the passive criteria in accordance with NEI 95-10. In addition, the staff determined that the applicant evaluated the identified passive commodities to determine they were long-lived and that the remaining passive, long-lived components were determined to be subject to an AMR.

The staff performed a sample review to determine if the screening methodology outlined in the LRA and implementing procedures was adequately implemented. During the scoping and screening methodology audit, the staff reviewed the electrical screening report, discussed the report with the applicant, and confirmed proper implementation of the screening process.

2.1.5.4.3 Conclusion

Based on its review of the LRA, the screening implementation procedure, drawings, discussion with the applicant, and a sample of the results of the screening methodology, the staff concludes that the applicant's methodology to identify electrical SSCs within the scope of license renewal and subject to an AMR is in accordance with the requirements of 10 CFR 54.21(a)(1) and, therefore, acceptable.

2.1.5.5 Conclusion for Screening Methodology

Based on its review of the LRA, the screening implementing procedures, discussions with the applicant's staff, and a sample review of screening results, the staff concludes that the applicant's screening methodology was consistent with the guidance contained in the SRP-LR and identified those passive, long-lived components within the scope of license renewal that are subject to an AMR. The staff concludes that the applicant's methodology is consistent with the requirements of 10 CFR 54.21(a)(1) and, therefore, is acceptable.

2.1.6 Summary of Evaluation Findings

Based on its review of the information presented in LRA Section 2.1, the supporting information in the scoping and screening implementing procedures and reports, the information presented during the scoping and screening methodology audit, discussions with the applicant sample system reviews, and the applicant's responses dated January 27, 2012, to the staff's RAIs dated January 5, 2012, the staff confirms that the applicant's scoping and screening methodology is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1). The staff also concludes that the applicant's description and justification of its scoping and screening methodology are adequate to meet the requirements of 10 CFR 54.21(a)(1). From this review, the staff concludes that the applicant's methodology for identifying systems and structures within the scope of license renewal and SCs requiring an AMR is acceptable.

2.2 Plant-Level Scoping Results

2.2.1 Introduction

In LRA Section 2.1, the applicant described the methodology for identifying SSCs within the scope of license renewal. In LRA Section 2.2, the applicant used the scoping methodology to determine which SSCs must be included within the scope of license renewal. The staff reviewed the plant-level scoping results to determine whether the applicant has properly identified all systems and structures relied upon to mitigate DBEs, as required by 10 CFR 54.4(a)(1); systems and structures, the failure of which could prevent satisfactory accomplishment of any safety-related functions, as required by 10 CFR 54.4(a)(2); and systems and structures relied on in safety analyses or plant evaluations to perform functions required by regulations referenced in 10 CFR 54.4(a)(3).

2.2.2 Summary of Technical Information in the Application

In LRA Table 2.2-1, the applicant listed plant mechanical systems, structures, and electrical and I&C systems within the scope of license renewal. Based on the DBEs considered in the plant's CLB, other CLB information relating to nonsafety-related systems and structures, and certain regulated events, the applicant identified plant-level systems and structures within the scope of license renewal as defined by 10 CFR 54.4.

2.2.3 Staff Evaluation

In LRA Section 2.1, the applicant described its methodology for identifying systems and structures within the scope of license renewal and subject to an AMR. The staff reviewed the scoping and screening methodology and provides its evaluation in the SER Section 2.1. To verify the applicant properly implemented its methodology, the staff's review focused on the implementation results shown in LRA Table 2.2-1, "Plant Level Scoping Results," to confirm that there were no omissions of plant-level systems and structures within the scope of license renewal.

The staff determined if the applicant properly identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4. The staff reviewed systems and structures that the applicant did not identify as within the scope of license renewal to verify if the systems and structures have any intended functions requiring their inclusion within the scope of license renewal. The staff's review of the applicant's implementation was conducted in accordance with the guidance in SRP-LR Section 2.2, "Plant-Level Scoping Results."

In RAI 2.2-1, dated March 9, 2012, the staff noted Table 2.2-1 provides the results of applying the license renewal scoping criteria to the systems, structures, and commodities. The license renewal scoping criteria was described in LRA Section 2.1. The following UFSAR systems could not be located in LRA Table 2.2-1: plant monitoring system (UFSAR Section 1.2.4.3.1.7, "Plant Monitoring System" (PMS)), area radiation monitoring system (UFSAR Section 7.1.2.1.12, "Area Radiation Monitoring System"), emergency response facility data system (UFSAR Section 7.1.2.1.46, "Emergency Response Facility Data System"), and chemistry laboratory air supply and exhaust systems (UFSAR Section 9.4.3.2.4, "Chemistry Laboratory Expansion"). The applicant was requested to justify the exclusion of the previously noted systems from Table 2.2-1.
In its response, by letter dated March 20, 2012, the applicant provided the following clarifications of where the above systems are located:

- The emergency response facilities data system and plant monitoring system are subsystems of the miscellaneous I&C system, which is described in Table 2.2-1 as not being within the scope of license renewal.
- The chemistry laboratory air supply and exhaust systems is a subsystem of the miscellaneous ventilation system, which is described in Table 2.2-1 as not being within the scope of license renewal.
- The area radiation monitoring system is a subsystem of the plant leak detection and radiation monitoring system, which is included in LRA Table 2.2-1 as being within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.2-1 acceptable because the applicant explained that these systems are subsystems within systems that are included in Table 2.2-1. Therefore, the staff's concern described in RAI 2.2-1 is resolved.

2.2.4 Conclusion

The staff reviewed LRA Section 2.2, the RAI 2.2-1 response, and UFSAR supporting information to determine whether the applicant failed to identify any systems and structures within the scope of license renewal. The staff finds no such omissions. Based on its review, the staff concludes that the applicant has adequately identified the systems and structures within the scope of license renewal in accordance with 10 CFR 54.4.

2.3 Scoping and Screening Results: Mechanical Systems

This section documents the staff's review of the applicant's scoping and screening results for mechanical systems. Specifically, this section discusses:

- reactor vessel, internals, and reactor coolant system (RCS)
- engineered safety features (ESF) systems
- auxiliary systems
- steam and power conversion systems

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SCs within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus allowed the staff to confirm that there were no omissions of mechanical system components that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the information in the LRA was the same for all mechanical systems. The objective was to determine whether the applicant has identified, in accordance with 10 CFR 54.4, components and supporting structures for mechanical systems that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections and drawings, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each mechanical system to determine whether the applicant has included in the scope of license renewal all components with intended functions delineated under 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all intended functions delineated under 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether the functions are performed with moving parts or a change in configuration or properties or the SCs are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.3.1 Reactor Vessel, Internals, and Reactor Coolant System

LRA Section 2.3.1 identifies the reactor vessel, internals, and RCS SCs subject to an AMR for license renewal. The applicant described the supporting SCs of reactor vessel, internals, and RCS in the following LRA sections:

- 2.3.1.1, "Reactor Coolant Pressure Boundary"
- 2.3.1.2, "Reactor Pressure Vessel"
- 2.3.1.3, "Reactor Vessel Internals"

The staff's findings on review of LRA Sections 2.3.1.1 – 2.3.1.3 are provided in SER Sections 2.3.1.1 – 2.3.1.3.

2.3.1.1 Reactor Coolant Pressure Boundary

2.3.1.1.1 Summary of Technical Information in the Application

The RCPB consists of those systems and components that contain or transport fluids coming from, or going to, the reactor core. The reactor recirculation system provides coolant flow through the core. The reactor recirculation system consists of the two recirculation pump loops external to the reactor vessel. Each external loop contains one motor-driven recirculation pump and provides the piping path to the reactor vessel jet pumps. The reactor recirculation system is mainly within primary containment; however, the system has instrumentation lines that penetrate containment, with tubing, valves, and transmitters in the reactor building outside the primary containment.

The intended functions of the RCPB within the scope of license renewal include the following:

- maintains integrity of RCPB
- provides isolation and integrity of primary containment
- provides structural support or restraint to SSCs in scope for license renewal
- senses process conditions and generates reactor protection system (RPS) or ESF actuation signals
- provides capability to trip recirculation pumps
- provides the flow path to, maintains the pressure boundary of, and receives isolation signal from the standby liquid control (SLC) injection

LRA Table 2.3.1-1 identifies the RCPB component types within the scope of license renewal and subject to an AMR.

2.3.1.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.1.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the reactor coolant pressure boundary components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.2 Reactor Pressure Vessel

2.3.1.2.1 Summary of Technical Information in the Application

The reactor pressure vessel (RPV) is a vertical, cylindrical pressure vessel of welded construction designed by General Electric (GE). The RPV has a cylindrical shell, bottom head, and upper head. Both the upper head and upper shell have a forged flange welded to them for vessel closure. The upper head is secured to the RPV by studs, nuts, and washers. The RPV vessel flanges are sealed by two concentric rings designed to prevent leakage through the inner or outer seal at any operating condition.

The intended functions of the RPV within the scope of license renewal include the following:

- maintains the RCPB
- provides a barrier to radiation release
- contains and supports the reactor core, internals, and coolant moderator
- provides a floodable volume in which the core can be adequately cooled in the event of a breach in the RCPB
- provides structural support or restraint to SSCs in scope for license renewal
- provides the flow path for SLC system injection

The RPV evaluation boundary consists of the vessel shell, heads, closure flanges, vessel closure bolting, nozzles, safe ends, safe end extensions, nozzle caps, nozzle flanges (including blank flanges), in-core penetrations (housings), internal attachments (jet pump riser support pads, core spray (CS) brackets, steam dryer holddown brackets, guide rod brackets, surveillance specimen brackets, steam dryer support brackets, and feedwater sparger brackets), stabilizer brackets, support skirt and refueling bellows bracket, control rod drive (CRD) stub tubes and housings, and associated pressure boundary bolting.

LRA Table 2.3.1-2 identifies the RPV component types within the scope of license renewal and subject to an AMR.

2.3.1.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.2.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the RPV components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.1.3 Reactor Vessel Internals

2.3.1.3.1 Summary of Technical Information in the Application

The reactor vessel internal components include the core (including fuel assemblies and control rod assemblies, control rod guide thermal sleeves, guide rods, in-core dry tubes, in-core guide tubes), core support structure (control rode guide tubes, core plate and holddown bolts, fuel supports, shroud, shroud support, access hole covers, and top guide), CS lines, rings, nozzles, thermal sleeves and spargers, differential pressure line, feedwater spargers, jet pump assemblies and instrumentation, low-pressure coolant injection (LPCI) couplings, steam dryer, shroud head, and steam dryer assembly.

The intended functions of the reactor vessel internals (RVIs) within the scope of license renewal include the following:

- maintain the RCPB
- contain and support the reactor core, internals, and coolant moderator
- provide a floodable volume in which the core can be adequately cooled in the event of a breach in the RCPB
- maintain core geometry to ensure control rods and emergency core cooling systems (ECCS) can perform their safety functions
- provide active nuclear fuel and cladding
- provide emergency reactor shutdown capability
- provide negative reactivity to achieve and maintain shutdown
- distribute coolant

The RVIs evaluation boundary includes the core support subcomponents and other reactor vessel internal components. UFSAR Figure 3.9-4 provides the details of the RV internals.

LRA Table 2.3.1-3 identifies the RVIs component types within the scope of license renewal and subject to an AMR.

2.3.1.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.1.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.1.3.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the RVIs components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2 Engineered Safety Features

LRA Section 2.3.2 identifies the ESF SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the ESFs in the following LRA sections:

- 2.3.2.1, "Containment Atmosphere Control System"
- 2.3.2.2, "Core Spray System"
- 2.3.2.3, "High-Pressure Coolant Injection System"
- 2.3.2.4, "Reactor Core Isolation Cooling System"
- 2.3.2.5, "Residual Heat Removal System"
- 2.3.2.6, "Standby Gas Treatment System"

The staff's findings on review of LRA Sections 2.3.2.1 – 2.3.2.6 are in SER Sections 2.3.2.1 –2.3.2.6.

2.3.2.1 Containment Atmosphere Control System

2.3.2.1.1 Summary of Technical Information in the Application

LRA Section 2.3.2.1 states that the purpose of the containment atmosphere control system is for inerting primary containment with nitrogen, purging containment with air to permit maintenance, limiting differential pressure between the drywell and suppression chamber, monitoring of containment temperature, pressure, hydrogen and oxygen levels, and controlling combustible gas concentrations after a loss-of-coolant accident (LOCA). The containment atmosphere control system is comprised of the liquid nitrogen supply subsystem that is common to LGS Units 1 and 2, containment inerting and purging subsystem, containment vacuum relief subsystem, combustible gas analyzer subsystem, and containment hydrogen recombiner subsystem and instrumentation used to monitor containment temperature and pressure.

The intended functions of the containment atmosphere control system are to sense process conditions and generate signals for reactor trip or ESF actuation, provide primary containment boundary, provide emergency heat removal from primary containment and provide containment pressure control, control combustible gas mixtures in the primary containment atmosphere, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The containment atmosphere control system is relied on in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for EQ (10 CFR 50.49), fire protection (10 CFR 50.48), and SBO (10 CFR 50.63).

LRA Table 2.3.2-1 identifies the containment atmosphere control system component types that are within the scope of license renewal and subject to an AMR.

2.3.2.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.1.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the containment atmosphere control system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.2 Core Spray System

2.3.2.2.1 Summary of Technical Information in the Application

The intended functions of the CS system within the scope of license renewal include the following:

- provides emergency core cooling
- provides primary containment isolation and integrity
- provides an injection flowpath into the vessel for high-pressure coolant injection (HPCI)

- provides secondary containment boundary
- senses process conditions and generates RPS or ESF actuation signals

The CS evaluation boundary includes the CS suction strainers in the suppression pool through the upstream side of the CS discharge outboard containment isolation valve; beyond this point is considered part of the RCPB.LRA Table 2.3.2-2 identifies the CS system component types within the scope of license renewal and subject to an AMR.

2.3.2.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.2.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the CS system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.3 High-Pressure Coolant Injection System

2.3.2.3.1 Summary of Technical Information in the Application

The HPCI system is designed to pump water into the RPV over a wide range of pressures. The HPCI system uses a steam turbine to drive a booster and main pump. To assist with RPV depressurization, the driving steam is taken from upstream of the main steam isolation valve (MSIV). Water is delivered to the RPV though one of the CS spargers and one of the feedwater headers to the feedwater spargers. The HPCI system normally takes suction from the condensate storage tank (CST), but can take suction from the suppression pool. The HPCI pump is located sufficiently below both suction sources to provide flooded pump suction and to meet net positive suction head requirements.

The intended functions of the HPCI system within the scope of license renewal include the following:

- provides emergency core cooling
- provides primary containment isolation and integrity
- senses process conditions and generates RPS or ESF actuation signals

LRA Table 2.3.2-3 identifies the HPCI system component types that are within the scope of license renewal and subject to an AMR.

2.3.2.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.3.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the HPCI system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.4 Reactor Core Isolation Cooling System

2.3.2.4.1 Summary of Technical Information in the Application

The reactor core isolation cooling (RCIC) system consists of a turbine, pump, piping, valves, accessories, and instrumentation capable of delivering makeup water to the RPV to maintain sufficient reactor water inventory and adequate core cooling. The RCIC is automatically initiated at a predetermined low reactor water level. The RCIC turbine steam supply comes from the RPV just upstream of the MSIV valves.

During normal modes of operation the turbine-driven pump takes suction from the condensate CST and injects into the RPV through one of the feedwater headers to feedwater spargers. There is automatic suction source switchover to the suppression pool when the CST is exhausted.

The intended functions of the RCIC system within the scope of license renewal include the following:

- provides high-pressure coolant flow to the reactor vessel
- removes residual heat from the RCS
- provides primary containment isolation and integrity
- senses process conditions and generates RPS or ESF actuation signals

LRA Table 2.3.2-4 identifies the RCIC system component types within the scope of license renewal and subject to an AMR.

2.3.2.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3..2.4 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.4.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the RCIC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.5 Residual Heat Removal System

2.3.2.5.1 Summary of Technical Information in the Application

The residual heat removal (RHR) system is a four loop system. Each loop has its own motor-driven pump, piping, valves, instrumentation, controls, and a suction source from the suppression pool, and is capable of discharging water to the RPV or back to the suppression pool. In addition, loops A and B have heat exchangers, the ability to take suction from the reactor recirculation system suction or from the spent fuel pool. The safety-related SW system cools the heat exchangers. Loops A and B also can discharge to reactor recirculation discharge. Additionally, the pumps in loops C and D can be aligned by crossties for use as alternates to the pumps in loops A and B, respectively.

A spool piece is permanently installed on the shutdown cooling piping for making connection to the fuel pool cooling system so that RHR can provide assistance to cooling the fuel pool.

The RHR system has six modes of operation:

- LPCI
- suppression pool cooling (SPC)
- containment spray cooling (CSC)
- shutdown cooling (SDC)
- alternate decay heat removal
- fuel pool cooling

The intended functions of the RHR system within the scope of license renewal include the following:

- removes residual heat from the RCS
- provides primary containment isolation and integrity
- provides emergency core cooling
- provides emergency heat removal and pressure control to containment
- maintains suppression pool temperature below that required to condense steam after a LOCA
- provides additional cooling capacity for fuel pool

LRA Table 2.3.2-5 identifies the residual heat removal system component types that are within the scope of license renewal and subject to an AMR.

2.3.2.5.2 Staff Evaluation

The staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).
The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. In a letter dated February 17, 2012, the staff issued RAI 2.3.2.5-1, noting an inconsistency between units on the color coded green scoping for valves 1175A and 2175B compared to corresponding valves 2175A and 1175B and adjacent piping and pipe caps color coded red.

In a letter dated March 5, 2012, the applicant stated that the test connections containing tail pipe, pipe caps, and valves 1175B and 2175A are correctly highlighted in red as shown on drawings LR-M-51 sheets 3, zone G-6, and 5, zone G-3. The test connections containing valves 1175A and 2175B were inadvertently shown highlighted in green on drawings LR-M-51, sheet 1, zone G-3, and sheet 7, zone G-6, and should be shown highlighted in red. Drawing LR-M-51 sheets 1 and 7 will be revised to show the correct highlighting.

Based on its review, the staff finds the applicant's response to RAI 2.3.2.5-1 acceptable. The applicant clarified the discrepancy in the highlighting of RHR/CSC system components and revised the drawing in question. No new systems or components were included in the scope of license renewal as a result of this RAI response. Therefore, the staff's concern described in RAI 2.3.2.5-1 is resolved.

2.3.2.5.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the RHR components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.2.6 Standby Gas Treatment System

2.3.2.6.1 Summary of Technical Information in the Application

LRA Section 2.3.2.6 states that the standby gas treatment system (SGTS) filters halogen and particulate concentrations in gases that are potentially present in secondary containment following DBAs. The system automatically initiates, isolates, and maintains a negative pressure in secondary containment during these conditions.

The intended functions of the SGTS are to provide a secondary containment boundary, control and treat radioactive materials released to the secondary containment, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The SGTS is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48) and EQ (10 CFR 50.49).

LRA Table 2.3.2-6 identifies the SGTS component types within the scope of license renewal and subject to an AMR.

2.3.2.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.2.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.2.6.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the SGTS components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3 Auxiliary Systems

LRA Section 2.3.3 identifies the auxiliary systems SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the auxiliary systems in the following LRA sections:

- 2.3.3.1, "Auxiliary Steam System"
- 2.3.3.2, "Closed Cooling Water System"
- 2.3.3.3, "Compressed Air System"
- 2.3.3.4, "Control Enclosure Ventilation System"
- 2.3.3.5, "Control Rod Drive System"
- 2.3.3.6, "Cranes and Hoists"
- 2.3.3.7, "Emergency Diesel Generator Enclosure Ventilation System"
- 2.3.3.8, "Emergency Diesel Generator System"
- 2.3.3.9, "Fire Protection System"
- 2.3.3.10, "Fuel Handling and Storage"
- 2.3.3.11, "Fuel Pool Cooling and Cleanup System"
- 2.3.3.12, "Nonsafety-Related Service Water System"
- 2.3.3.13, "Plant Drainage System"
- 2.3.3.14, "Primary Containment Instrument Gas System"
- 2.3.3.15, "Primary Containment Leak Testing System"
- 2.3.3.16, "Primary Containment Ventilation System"
- 2.3.3.17, "Process Radiation Monitoring System"
- 2.3.3.18, "Process and Post-Accident Sampling System"
- 2.3.3.19, "Radwaste System"
- 2.3.3.20, "Reactor Enclosure Ventilation System"
- 2.3.3.21, "Reactor Water Cleanup System"
- 2.3.3.22, "Safety-Related Service Water System"
- 2.3.3.23, "Spray Pond Pump House Ventilation System"
- 2.3.3.24, "Standby Liquid Control System"
- 2.3.3.25, "Traversing In-core Probe System"
- 2.3.3.26, "Water Treatment and Distribution System"

The staff's findings on review of LRA Sections 2.3.3.1-2.3.3.26 are in SER Sections 2.3.3.1-2.3.3.26.

Auxiliary Systems Generic Requests for Additional Information

In RAI 2.3.3-1, dated March 9, 2012, the staff noted 20 instances on drawings in which the staff could not determine the basis for the change in scoping criteria from safety-related to nonsafety-related (i.e 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2)). The applicant was requested to clarify the scoping classification changes at these 20 locations.
In its response, by letter dated March 20, 2012, the applicant provided information to clarify the basis for the change in scoping criteria from 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2) for all 20 locations. The applicant stated that piping and components that perform or support a safety-related function are within the scope of license renewal based on the criteria in 10 CFR 54.4(a)(1) and that nonsafety-related piping components within the control enclosure, reactor enclosure, diesel generator enclosure, and primary containment that contain fluid are included within the scope of license renewal based on the criteria in 10 CFR 54.4(a)(2) caused by potential spacial interaction with safety-related components. The response stated that in six instances, the applicant determined there should not have been a transition from safety-related to nonsafety-related depicted on the scoping boundary drawings for the locations referenced in the staff's RAI. Therefore, the applicant stated that in these 6 instances the scoping boundary drawings would be revised to show the components referenced in the RAI as within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). For the remaining 14 locations the applicant confirmed that the scoping change depicted in the boundary drawing was correct and the components were correctly shown on the scoping drawings as within the scope license renewal in accordance with 10 CFR 54.4(a)(2). The staff reviewed the applicant's response and found it acceptable because the applicant revised 6 locations to properly identify safety-related components on the scoping boundary drawings, and because the applicant confirmed that the remaining 14 locations depicted nonsafety-related components.

However, the applicant's response did not include the revised drawings depicting the correct scoping classifications. Therefore, by letter dated May 18, 2012, the staff issued RAI 2.3.3-2, requesting the applicant to provide the revised scoping boundary drawings. Subsequent to the issuance of RAI 2.3.3-2, the staff performed NRC Inspection Procedure (IP) 71002 "License Renewal Inspection" review of the LGS site. During the IP 71002 inspection, the staff confirmed that the drawings referenced in RAI 2.3.3-1 have been revised consistent with the applicant's response. The staff's concern described in RAI 2.3.3-2 is resolved because the staff confirmed that the subject drawings have been revised consistent with applicant's RAI response.

The staff finds the applicant's responses to RAI 2.3.3-1 and RAI 2.3.3-2 acceptable because the applicant clarified the 20 scoping classification changes, which included six items revised from 10 CFR 54.4(a)(2) to 10 CFR 54.4(a)(1), and revised the license renewal boundary drawings. The staff confirmed that the scoping classifications were corrected on the revised license renewal boundary drawings. No new component types were identified as a result of the applicant's responses to the RAIs. Therefore, the staff's concern described in RAIs 2.3.3-1 and 2.3.3-2 are resolved.

2.3.3.1 Auxiliary Steam System

2.3.3.1.1 Summary of Technical Information in the Application

LRA Section 2.3.3.1 states that the intended function of the auxiliary steam system for license renewal is to resist nonsafety-related failure by maintaining leakage boundary integrity to preclude system interactions, and by maintaining structural support at physical interfaces with safety-related equipment. The LRA also states that the purpose of the auxiliary steam system is to provide steam for various startup and plant service functions. The system accomplishes this by using auxiliary steam boilers common to both LGS Units 1 and 2.

The auxiliary steam system intended function is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.3-1 identifies the auxiliary steam system component types within the scope of license renewal and subject to an AMR.

2.3.3.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.1.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the auxiliary steam system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.2 Closed Cooling Water System

2.3.3.2.1 Summary of Technical Information in the Application

LRA Section 2.3.3.2 states that the closed cooling water system is a normally operating closed-loop cooling system designed to provide cooling water to miscellaneous reactor auxiliary plant equipment and auxiliary plant equipment associated with nuclear and power conversion systems. The LRA also states that the closed cooling water system consists of the reactor enclosure cooling water and turbine enclosure cooling water systems.

The intended function of the closed cooling water system is to: provide primary containment boundary, resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function, and perform a function that demonstrates compliance with the NRC's EQ regulation (10 CFR 50.49) in safety analyses or plant evaluations.

LRA Table 2.3.3-2 identifies the closed cooling water system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.2.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the closed cooling water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.3 Compressed Air System

2.3.3.3.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3 states that the compressed air system is a mechanical system designed to supply plant equipment with compressed air and gas and supply service air outlets located throughout the plant with compressed air. The purpose of the compressed air system is to provide a supply of compressed air or gas for operation of pneumatic devices located throughout the plant.

The intended function of the compressed air system is to provide primary containment boundary and to provide motive power to safety-related components.

LRA Table 2.3.3-3 identifies the compressed air system component types within the scope of license renewal and subject to an AMR.

2.3.3.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.3 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.3.3 Conclusion

On the basis of the staff review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the compressed air system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.4 Control Enclosure Ventilation System

2.3.3.4.1 Summary of Technical Information in the Application

LRA Section 2.3.3.4 states that the control enclosure ventilation system is a normally operating mechanical system common to LGS Units 1 and 2, which provides ventilation, cooling, and control of environmental conditions in the control enclosure to maintain operability of safety-related equipment. The system also provides control of environmental conditions in the main control room for the safety and comfort of operating personnel.

The intended function of the control enclosure ventilation system is to provide a centralized area for control and monitoring of nuclear safety-related equipment and to maintain emergency temperature limits within areas containing safety-related components. The intended function of the control enclosure ventilation system is also to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The control enclosure ventilation system is also relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63).

LRA Table 2.3.3-4 identifies the control enclosure ventilation system component types within the scope of license renewal and subject to an AMR.

2.3.3.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.4 and UFSAR Sections 3.5.1.1.1, 6.4, 6.5.1.2, 7.3.2, 9.2.10.2, 9.4.1, 9A.2.5, and 9A.3.2.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components the applicant has identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The staff identified that LRA Tables 2.3.3-4 and 3.3.2-4 do not contain all the component types of the control enclosure ventilation system highlighted on the drawings. Also, the tables do not list any specific components and their housing types associated with "ducting and components type" (e.g., fans and fan housing, dampers and damper housings, fire dampers and fire damper housings, filters and filter housings, heating and cooling coils) as applicable.

Therefore, in a letter dated February 17, 2012, the staff issued RAI 2.3.3.4-1, requesting clarification as to whether these component types and all other applicable component types of the system are within the scope of license renewal, in accordance with 10 CFR 54.4(a), and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In a letter dated March 5, 2012, the applicant stated that the "Ducting and Components" component group includes fan housings, damper housings, fire damper housings, and filter housings. This practice is consistent with the GALL Report Table IX.B definition of ducting and components, which states that ducting and components includes "heating, ventilation, and air-conditioning (HVAC) components. Examples include ductwork equipment frames and housing, housing supports, including housings for valves, dampers (including louvers, gravity, and fire dampers), and ventilation fans." These components are within the scope of license renewal and subject to an AMR. Heating and cooling coils are included in "Heat Exchanger Components" component type. These components are reflected in LRA Tables 3.3.2-4 and 2.3.3-4.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.4-1 acceptable. The applicant clarified the discrepancy in the listing of the control enclosure ventilation system components. No new systems or components were included in the scope of license renewal as a result of this RAI response. Therefore, the staff's concern described in RAI 2.3.3.4-1 is resolved.

2.3.3.4.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the control enclosure ventilation system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.5 Control Rod Drive System

2.3.3.5.1 Summary of Technical Information in the Application

The CRD system consists of CRD mechanisms, the scram air header, and the hydraulic system. The CRD hydraulic system consists of hydraulic control units, a hydraulic power supply (pumps), interconnecting piping, and instrumentation. The CRD hydraulic system delivers clean, demineralized water for driving, rapid insertion, and cooling functions related to the operation of the control rod drives. The hydraulic control units manage water flow to and from the control rod.

The scram air header provides pneumatic supply to scram pilot solenoid valves, scram discharge volume (SDV) vent and drain valve actuators, and the hydraulic system flow control valve actuators. During a scram, each hydraulic control unit discharges water from the drive mechanisms through the scram outlet valves into the SDV. Energy from the nitrogen accumulators and from reactor pressure provides hydraulic power for rapid simultaneous insertion of all control rods.

The SDV consists of a header that drains to an instrument volume consisting of a vertical pipe with water level instrumentation. During normal plant operation, each SDV is empty and vented to the atmosphere through its open vent and drain valves. When a scram occurs, these vent and drain valves are closed to conserve reactor water.

LGS Unit 2 has permanent control rod friction test valves that are connected to measure the friction of the control rods during rod movement. These valves are manually isolated from the CRD system, except when friction testing is being performed.

The intended functions of the CRD system within the scope of license renewal include the following:

- maintains RCPB integrity
- provides emergency reactor shutdown
- provides primary containment isolation and integrity
- senses process conditions and generates RPS or ESF actuation signals
- provides alternate means of venting the scram air header to cause insertion of control rods

LRA Table 2.3.3-5 identifies the CRD system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.5 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.5.3 Conclusion

On the basis of its review of the LRA and UFSAR,, the staff concludes that the applicant has appropriately identified the CRD system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.6 Cranes and Hoists

2.3.3.6.1 Summary of Technical Information in the Application

LRA Section 2.3.3.6 states that the cranes and hoists are load-handling bridge cranes, jib cranes, lifting devices, monorails, and hoists provided throughout the facility to support operation and maintenance activities.

The intended function of the cranes and hoists is to provide physical support, shelter and protection for safety-related SSCs, and to provide a safe way to handle safety-related components and loads above or near safety-related components.

LRA Table 2.3.3-6 identifies the cranes and hoists component types within the scope of license renewal and subject to an AMR.

2.3.3.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff reviewed LRA Section 2.3.3.6 and the UFSAR as described in SER Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.6.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the cranes and hoists components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.7 Emergency Diesel Generator Enclosure Ventilation System

2.3.3.7.1 Summary of Technical Information in the Application

LRA Section 2.3.3.7 states that the EDG enclosure ventilation system is a standby safety-related mechanical system that provides ventilation and control of environmental conditions in the EDG enclosure.

The intended function of the EDG enclosure ventilation system is to maintain emergency temperature limits within areas containing safety-related components. The EDG enclosure ventilation system is relied upon in safety analyses or plant evaluation to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63).

LRA Table 2.3.3-7 identifies the EDG enclosure ventilation system component types within the scope of license renewal and subject to an AMR.

2.3.3.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.7 and UFSAR Sections 3.5.1.1.1 and 9.4.6 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant included in the scope of license renewal all components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant included all passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. In a letter dated February 17, 2012, the staff issued RAI 2.3.3.7-1, stating that LRA Tables 2.3.3-7 and 3.3.2-7 do not contain all the component types for the EDG enclosure ventilation system highlighted on the drawings. The tables do not list any specific components and their housing types associated with "ducting and components type," such as fans and fan housing, dampers and damper housings, fire dampers and fire damper housings, filters and filter housings, heating and cooling coils etc., as applicable.

Therefore, the staff requested clarification as to whether these component types and all other applicable component types of the system are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In a letter dated March 5, 2012, the applicant stated that "Ducting and Components" component group includes fan housings, damper housings, fire damper housings, and filter housings. This practice is consistent with the GALL Report Table IX.B definition of ducting and components, which states that ducting and components includes "heating, ventilation, and air-conditioning (HVAC) components. Examples include ductwork . . . equipment frames and housing, housing supports, including housings for valves, dampers (including louvers, gravity, and fire dampers), and ventilation fans." The "Ducting and Components" component type listed in LRA Table 3.3.2-7 includes ventilation and fire damper housings and fan housings. These components are subject to an AMR. Fans, dampers, and fire dampers are active components and not subject to an AMR. There are no filters or cooling coils in this system. As indicated on drawing LR-M-81, sheets 1 and 3, and LRA Tables 2.3.3-1 and 3.3.2-1, the steam supply to the unit heaters is evaluated with the auxiliary steam system.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.7-1 acceptable. The applicant clarified the discrepancy in the listing of the EDG enclosure ventilation system components. No new systems or components were included in the scope of license renewal as a result of this RAI response. Therefore, the staff's concern described in RAI 2.3.3.7-1 is resolved.

2.3.3.7.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the EDG enclosure ventilation system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.8 Emergency Diesel Generator System

2.3.3.8.1 Summary of Technical Information in the Application

LRA Section 2.3.3.8 states that the EDG system is a standby mechanical system designed to provide sufficient electrical power to important plant equipment when normal offsite power sources are not available.

The intended function of the EDG system is to provide motive power to safety-related components and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The EDG system is relied upon in safety analysis or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for SBO (10 CFR 50.63) and fire protection (10 CFR 50.48).

LRA Table 2.3.3-8 identifies the EDG system component types within the scope of license renewal and subject to an AMR.

2.3.3.8.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.8, UFSAR Sections 8.3.1, 9.5.4 through 9.5.8, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's requests for additional information as discussed below.

In RAI 2.3.3.8-1, dated March 9, 2012, the staff noted that license renewal boundary drawings LR-M-20, sheets 8 and 14, location F-5, depict ejector casings within the scope of license renewal for 10 CFR 54.4(a)(1). However, the ejector casing is not listed in Table 2.3.3-8 as a component type subject to an AMR. The applicant was requested to justify the exclusion of the ejector casing component type from LRA Table 2.3.3-8.

In its letter dated March 20, 2012, the applicant stated that the ejector bodies are included in LRA Table 2.3.3-8 as a component type, "Piping, piping components, and piping elements."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-1 acceptable because the applicant clarified that the ejector casing bodies are listed in LRA Table 2.3.3-8 as a "Piping, piping components, and piping elements" component type. Therefore, the staff's concern described in RAI 2.3.3.8-1 is resolved.

During its review, the staff noted that license renewal boundary drawings LR-M-20, sheets 8 and 14, locations B-4 and D-4, depict emergency diesel generator turbocharger casings as within the scope of license renewal for 10 CFR 54.4(a)(1). However, the emergency diesel generator turbocharger casing is not listed in LRA Table 2.3.3-8 as a component type subject to an AMR. Therefore, by letter dated March 9, 2012, the staff issued RAI 2.3.3.8-2 requesting the applicant to identify which component type in LRA Table 2.3.3-8 included the emergency diesel generator turbocharger casing, or to justify its exclusion from LRA Table 2.3.3-8.

In its letter dated March 20, 2012, the applicant stated that the emergency diesel generator turbocharger casings, shown on license renewal boundary drawing LR-M-20, sheets 8 and 14, are components subject to an AMR that are listed in LRA Table 2.3.3-8 as "Turbocharger Casing."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-2 acceptable because the applicant stated that the emergency diesel generator turbocharger casing are included in the component type "Turbocharger Casing" listed in LRA Table 2.3.3-8. Therefore, the staff's concern described in RAI 2.3.3.8-2 is resolved.

In RAI 2.3.3.8-3, dated March 9, 2012, the staff noted that license renewal boundary drawings LR-M-20, sheets 8 and 14, location F-3, depict exhaust silencer housings within the scope of license renewal for 10 CFR 54.4(a)(1). However, the exhaust silencer housing is not listed in Table 2.3.3-8 as a component type subject to an AMR. The applicant was requested to justify the exclusion of the exhaust silencer component type from LRA Table 2.3.3-8.

In its letter dated March 20, 2012, the applicant stated that the exhaust silencer housing and internals are subject to an AMR and are included in LRA Table 2.3.3-8 as a component type, "Piping, piping components, and piping elements."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-3 acceptable because the applicant clarified that the exhaust silencer housing and internals are included in LRA Table 2.3.3-8 as a "Piping, piping components, and piping elements" component type. Therefore, the staff's concern described in RAI 2.3.3.8-3 is resolved.

In RAI 2.3.3.8-4, dated March 9, 2012, the staff noted license renewal boundary drawings LR-M-20, sheets 3 and 9, locations D-3 and D-7, depict flame arrestor housings within the scope of license renewal for 10 CFR 54.4(a)(1). However, the flame arrestor housing is not listed in LRA Table 2.3.3-8 as a component type subject to an AMR. The applicant was requested to justify the exclusion of the flame arrestor housing component type from LRA Table 2.3.3-8.

In its letter dated March 20, 2012, the applicant stated that the flame arrestor housings are subject to an AMR and are included in LRA Table 2.3.3-8 as a component type, "Piping, piping components, and piping elements."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-4 acceptable because the applicant clarified that the flame arrestor housings are included in LRA Table 2.3.3-8 as a "Piping, piping components, and piping elements" component type. Therefore, the staff's concern described in RAI 2.3.3.8-4 is resolved.

In RAI 2.3.3.8-5, dated March 9, 2012, the staff noted LRA Section 2.1.1 states that the in-scope portions of mechanical systems and structures are highlighted in color on the license renewal boundary drawings. For the EDG system, the applicant includes the diesel engines within the license renewal scoping boundary. License renewal boundary drawings LR-M-20, sheets 3 and 9, location F-5, depict diesel engines 1AG501 and 2AG501 as not being within the scope of license renewal. Although the applicant states in Note 7 on license renewal boundary drawing LR-M-20 that the in-scope diesel fuel oil supply system boundary stops at the fuel injectors of the diesel generator because the fuel injectors are excluded from AMR, the license renewal boundary drawings appear to contradict the applicant's methodology for highlighting the in-scope components (the diesel engines) as described in LRA Section 2.1.1. The applicant was requested to justify why the diesel engines depicted on license renewal boundary drawings LR-M-20, sheets 3 and 9, are indicated as not being within the scope of license renewal.

In its letter dated March 20, 2012, the applicant explained that the diesel engine boxes, as shown on license renewal boundary drawings LR-M-20, sheets 3 and 9, were not shown in green because those drawings depict the diesel fuel oil storage and transfer system components within the scope of license renewal and that the diesel engine box is outside the boundary of the diesel fuel oil storage and transfer system. The applicant also stated that the first paragraph on LRA page 2.3-84, under the scoping boundary discussion in LRA Section 2.3.3.8, states that the license renewal scoping boundary for the diesel fuel oil storage and transfer system ends at the connection point to the diesel engines. The applicant further stated that LRA Section 2.3.3.8 does include the diesel engines within the scoping boundary for license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.8-5 acceptable because the staff confirmed that the applicant has properly identified the components in the diesel fuel oil storage and transfer system that are within the scope of license renewal and the staff confirmed that LRA Section 2.3.3.8 lists the diesel engines as within the scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.8-5 is resolved.

2.3.3.8.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI responses, the staff concludes the applicant appropriately identified the EDG system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.9 Fire Protection System

2.3.3.9.1 Summary of Technical Information in the Application

The fire protection system is a mechanical system common to LGS Units 1 and 2, which is designed to provide detection and suppression of a fire at the plant. The fire protection system includes water, foam, carbon dioxide, and halon suppression systems. It also includes active and passive features such as fire doors, dampers, penetration seals, fire wraps, fire barrier walls and slabs, and oil retention dikes.

The fire protection system is intended to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The fire protection system has leakage boundary intended function and the potential for spatial interaction with safety-related equipment located in the vicinity of water-filled fire protection system piping. The fire protection system also is relied upon in the safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection in 10 CFR 50.48 for LGS Units 1 and 2. The fire protection system also provides the capability to control postulated fires in plant areas to maintain safety shutdown ability.

LRA Table 2.3.3-9 identifies the fire protection system component types within the scope of license renewal and subject to an AMR.

2.3.3.9.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.9, the UFSAR, and LRA drawings using the evaluation methodology described in SER Section 2.3 and guidance in SRP-LR, Section 2.3. During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant included in the scope of license renewal all components with intended functions pursuant to 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant included all passive or long-lived components subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

The staff also reviewed the following fire protection document cited in the CLB listed in the LGS Units 1 and 2 Operating License Conditions 2.C(3): NRC Safety Evaluation Report, issued August 1983, through Supplement 9, issued August 1989, and Safety Evaluation, dated November 20, 1995.

Based on the documents above, the staff reviewed the LGS Units 1 and 2 commitment to 10 CFR 50.48, "Fire Protection" (i.e., approved fire protection program). The review consisted of a point-by-point comparison with Appendix A to the Branch Technical Position Chemical and Mechanical Engineering Branch 9.5-1, "Guidelines for Fire Protection for Nuclear Power Plants," Revision 2, issued July 1981, documented in the UFSAR Section 9.5.1, and Appendix 9A, "Fire Protection Evaluation Report."
During its review of LRA Section 2.3.3.9, the staff identified areas in which additional information was necessary to complete its review of the applicant's scoping and screening results.

By letter dated January 24, 2012, the staff issued RAI 2.3.3.9-1, noting that the LRA boundary drawing LR-M-22, sheet 5, at location F3, shows the cable spreading room's fire walls and associated components, including fire doors, fire dampers, and penetration seals as out of scope (i.e., not colored in green). The staff requested the applicant to verify whether the cable spreading room's fire walls and associated components are in the scope of license renewal in accordance with 10 CFR 54.4(a) and if they are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The staff requested that if these fire walls and associated components are excluded from the scope of license renewal and are not subject to an AMR, the applicant provide justification for the exclusion.

By letter dated February 16, 2012, the applicant responded to RAI 2.3.3.9-1. The applicant stated that the cable spreading room's fire walls, as shown on boundary drawing LR-M-22, sheet 5, location F3, are in the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR in accordance with 10 CFR 54.21(a)(1) as shown on LRA Table 3.3.2-4. The boundary drawings were prepared to only show the mechanical systems and equipment that are in scope for license renewal, as described in boundary drawing LR-M-00, sheet 2, Note 3. The fire walls are structural components and were, therefore, not shown as green on the LR-M-22, sheet 5, boundary drawing. Further, the applicant stated that the cable spreading room's fire walls associated components, including fire doors and penetration seals, are in the scope of license renewal in accordance with 10 CFR 54.4(a) as shown on LRA Table 3.3.2-9. These components are subject to an AMR in accordance with 10 CFR 54.21(a)(1). The fire dampers are in the scope of license renewal in accordance with 10 CFR 54.4(a). The fire dampers are active per NEI 95-10; therefore, the dampers are not subject to an AMR and were not included in LRA Table 3.3.2-9. However, the damper housing is passive and is subject to an AMR. The damper housings are evaluated with the control enclosure ventilation system AMR included in the component type of ducting and components as shown on LRA Table 3.3.2-4.

The staff reviewed the applicant's response to RAI 2.3.3.9-1, which confirmed that the cable spreading room's fire walls and associated components in question, including fire doors, fire dampers, and penetration seals, are in the scope of license renewal and subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.9-1 is resolved.

By letter dated January 24, 2012, the staff issued RAI 2.3.3.9-2 and asked the applicant to determine if LRA Tables 2.3.3-9 and 3.3.2-9 should include the following fire protection components:

- fire hose stations, fire hose connections, and hose racks
- fire protection water curtain systems in the reactor enclosures and hatchways
- floor drains for fire water

- passive components in fire protection water and foam solution storage tanks' heat exchanger
- fire dampers
- fire retardant coating (fireproofing material) for structural steel members
- passive components in diesel-driven fire pump engine
- passive components in lightning plant protection system (National Fire Protection Association (NFPA) 78, Lightning Protection Code)

If the applicant determined that LRA Tables 2.3.3-9 and 3.3.2-9 should not include these components, the staff asked the applicant to justify the exclusion of these components from the scope of license renewal.

In its letter dated February 16, 2012, the applicant provided the results of the scoping and screening for the fire protection component types addressed in RAI 2.3.3.9-2.

In reviewing its response to RAI 2.3.3.9-2, the staff found that the applicant had addressed and resolved each item in the RAI, as discussed below.

Hose stations, hose connections, and hose racks are in the scope of license renewal and subject to an AMR. These items include valves, couplings, and fittings, and are included in LRA Table 3.3.2-9 as the "Valve Body," "Piping," "Piping Components," and "Piping Elements," component types. The applicant determined that the fire hoses' associated racks are periodically replaced in accordance with NFPA standards and are, therefore, short-lived and not subject to an AMR.

The applicant confirmed that water curtain systems are included in the scope of license renewal, and system components (values, spray nozzles, and piping) are evaluated under items description "Valve Body," "Spray Nozzles," "Piping," "Piping Components," and "Piping Elements," in LRA AMR Table 3.3.2-9.

The floor drains for fire water are evaluated under "Plant Drainage System" in LRA Section 2.3.3.13; they are in the scope of license renewal and subject to an AMR. The drains are included in LRA AMR Table 3.3.2-13 as the piping, piping components, and piping elements component type.

The applicant stated that the foam solution tank and backup fire water storage tank are within the scope of license renewal. The applicant further stated there is no heat exchanger installed in these tanks and no passive subcomponents of these tanks that would be subject to an AMR.

The applicant confirmed that fire damper housings are passive components and subject to an AMR. The damper housings are listed in LRA AMR Tables 3.3.2-4, 3.3.2-20, 3.3.2-7, and 3.3.2-23 in the ducting and components component type.

Fire retardant coating on structural steel is known as "Cafecote" and is included in the component category "Fire Barriers" in LRA Table 3.3.2-9. It is in the scope of license renewal and subject to an AMR.

The applicant included passive components in diesel-driven fire pump engines in the scope of license renewal. The applicant stated that these components are not subject to an AMR because the diesel engines include various components necessary to support engine operation. Many of these components are either located internal to the engine or are physically mounted on the engine. These components are considered integral subcomponent parts of the active diesel engine assembly. Further, the applicant clarified that the fuel oil components that are not part of the active diesel engine assembly are subject to an AMR. These components are the diesel oil day tank and fuel inlet and return piping and components from the tank up to the diesel engine assembly. The applicant also confirmed that these components are included in LRA Table 3.3.2-9 as the component type tanks (diesel oil day tank), valve body, and piping, piping components, and piping elements.

In regard to passive components in the lightning plant protection system, the applicant stated that LGS does not have a plant lightning protection system; however, passive lightning protection components at LGS Units 1 and 2 are provided for equipment and personnel protection.

By letter dated April 13, 2012, the staff issued followup RAI 3.3.2.9-2.1, requesting the applicant to clarify why the passive lightning protection components are not required for compliance with 10 CFR 50.48 and within the scope of license renewal. The staff requested the applicant to justify excluding these components from the scope of license renewal and an AMR.

In its letter dated April 27, 2012, the applicant stated that the purpose of the lightning protection system is to provide protection of equipment and personnel from hazards from exposure of lightning. Further, the applicant stated that lighting protection at LGS Units 1 and 2 is provided for the implementation of good design practice and for insurance and property protection purposes.

Based on its review, the staff finds the applicant's response to RAI 3.3.2.9-2.1 acceptable because the applicant explained that the lightning protection system at LGS Units 1 and 2 is for property protection and loss prevention and, therefore, not safety-related. The staff also confirmed that NRC SER, dated August 1983, through Supplement 9, dated August 1989, and Safety Evaluation, dated November 20, 1995, do not discuss the lightning protection system. Therefore, the staff's concern described is RAI 2 RAI 3.3.2.9-2.1 is resolved.

Based on its review, the staff found that the applicant had addressed and resolved each item in response to the RAI as discussed above. Therefore, the staff found the response to RAI 2.3.3.9-2 acceptable for the purpose of determining if the applicant has adequately identified the fire protection system components within the scope of license renewal.

By letter dated January 24, 2012, the staff issued RAI 2.3.3.9-3, stating that LRA Section 2.4, "Scoping and Screening Results: Structures," provides the scoping and screening results of various structures within the scope of license renewal and subject to an AMR. Further, Section 2.4 states that the fire barriers are evaluated separately with the fire protection system, LRA Section 2.3.3.9. LRA Table 2.3.3.9 includes fire barriers (doors), fire barriers (fire-rated enclosures), fire barriers (for steel components), fire barriers (penetration seals), fire barriers (walls and slabs), which are subject to an AMR. The staff requested the applicant to provide a summary of the list of buildings or structures where fire barriers are credited and the specific types of barriers at these locations in the LGS's fire protection program.

By letter dated February 16, 2012, the applicant responded to RAI 2.3.3.9-3 and stated that the fire barriers within the scope of license renewal and subject to an AMR are described in LRA Table 2.3.3-9. These barrier types are located in structures within the scope of license renewal. The applicant's response to RAI 2.3.3.9-3 included a table of the fire barrier types for each structure within the scope of license renewal that contain fire barriers.

In reviewing its response to RAI 2.3.3.9-3, the staff found that the applicant had addressed the staff concern on fire barriers credited in LGS's fire protection program, including the specific type and location. Therefore, the staff's concern described in RAI 2.3.3.9-3 is resolved.

2.3.3.9.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the fire protection system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.10 Fuel Handling and Storage System

2.3.3.10.1 Summary of Technical Information in the Application

LRA Section 2.3.3.10 describes the fuel handling and storage system as consisting of the spent fuel storage racks and special storage racks within the spent fuel storage pools and fuel handling equipment. The LRA states that the purpose of the fuel handling and storage system is to provide safe and effective storage, transport, and handling of nuclear fuel from the time it enters the facility until it leaves the facility.

The fuel handling and storage system's intended functions are to prevent criticality of fuel assemblies stored in the spent fuel pool, provide protection for safe storage of new and spent fuel, provide shielding protection for personnel and equipment and components, provide safe means for handling safety-related components and loads above or near safety-related components, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of safety-related functions.

LRA Table 2.3.3-10 identifies the fuel handling and storage system component types within the scope of license renewal and subject to an AMR.

2.3.3.10.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.10 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.10.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the fuel handling and storage system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.11 Fuel Pool Cooling and Cleanup System

2.3.3.11.1 Summary of Technical Information in the Application

LRA Section 2.3.3.11 states that the fuel pool cooling and cleanup system is a normally operating system designed to remove decay heat from the spent fuel pool and maintain specified fuel pool water temperature, level, purity, and clarity.

The intended function of the fuel pool cooling and cleanup system is to ensure cooling in the spent fuel pool to maintain fuel within acceptable temperature limits and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.3-11 identifies the fuel pool cooling and cleanup system component within the scope of license renewal and subject to an AMR.

2.3.3.11.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.11.3 Conclusion

The staff concludes that the applicant has appropriately identified the fuel pool cooling and cleanup system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.12 Nonsafety-Related Service Water System

2.3.3.12.1 Summary of Technical Information in the Application

LRA Section 2.3.3.12 states that the nonsafety-related SW system designed to supply the cooling water required for normal plant operation has no safety-related functions. The nonsafety-related SW system takes heat from heat exchangers in the turbine, reactor, control, and radwaste enclosures and transfers this heat to the cooling towers where it is dissipated.

The intended function of the nonsafety-related SW system is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.3-12 identifies the nonsafety-related SW system component types within the scope of license renewal and subject to an AMR.

2.3.3.12.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.12, UFSAR Section 9.2.1, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.12-1, dated March 9, 2012, the staff noted license renewal boundary drawings LR-M-10, sheets 5 and 10, locations H-2 and H-4, depict the 6-inch JBD-107/207 and 6-inch JBD-132/232 lines as being within the scope of license renewal based on the criteria of 10 CFR 54.4(a)(2) with continuations to and from license renewal boundary drawings LRM-10, sheets 3 and 8. However, the continuations of these lines on license renewal boundary drawings, LR-M-10, sheets 3 and 8, are depicted as not being within the scope of license renewal. The applicant was requested to clarify the correct scoping classification of these pipe lines.

In its response, dated March 20, 2012, the applicant stated that the continuations of the 6-inch JBD-107/207 and 6-inch JBD-132/232 lines to and from license renewal boundary drawings LR-M-10, sheets 3 and 8 should be within the scope of license renewal up to the tees with the 24-inch cooling water headers. During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.3.12-1.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.12-1 acceptable because the applicant clarified that the 6-inch JBD-107/207 and 6-inch JBD-132/232 lines, to and from license renewal boundary drawings LR-M-10, sheets 3 and 8, are within the scope of license renewal for 10 CFR 54.4(a)(2) and revised the license renewal boundary drawings. Therefore, the staff's concern described in RAI 2.3.3.12-1 is resolved.

2.3.3.12.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI responses, the staff concludes the applicant appropriately identified the nonsafety-related SW system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.13 Plant Drainage System

2.3.3.13.1 Summary of Technical Information in the Application

LRA Section 2.3.3.13 states that the plant drainage system is designed to collect various liquid wastes generated in the operation of the plant.

The intended function of the plant drainage system is to provide emergency core cooling, in which the equipment provides coolant directly to the core, to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The plant drainage system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48). LRA

Table 2.3.3-13 identifies the plant drainage system component types within the scope of license renewal and subject to an AMR.
2.3.3.13.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.13, UFSAR Sections 3.4.1.1, 3.6.1, 9.3.3, 9.5.1, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.13-1, dated March 9, 2012, the staff noted on license renewal boundary drawing, LR-M-64, sheet 1, location G-8, that the continuation of pipe lines depicted in the scope of license renewal could not be found on any other license renewal boundary drawings. The applicant was requested to locate the continuations, and if the continuation line cannot be shown on license renewal boundary drawings, to provide additional information describing the extent of the scoping boundary and to verify whether or not there are additional AMR component types between the continuation and the termination of the scoping boundary. The applicant was also requested to provide additional information to clarify the change in the scoping classification if a section of the piping changes scoping classification over the continuation.

In its letter dated March 20, 2012, the applicant stated that the piping does not continue to any other license renewal boundary drawings. These drain lines originate at floor drains within the washdown areas and all component types to the license renewal boundary are currently within the license renewal scoping boundary.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.13-1 acceptable because the applicant provided additional descriptions of the current license renewal boundary for the plant drainage system and indicated that all component types within the scoping boundary are currently subject to an AMR. Therefore, the staff's concern described in RAI 2.3.3.13-1 is resolved.

2.3.3.13.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the plant drainage system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.14 Primary Containment Instrument Gas System

2.3.3.14.1 Summary of Technical Information in the Application

LRA Section 2.3.3.14 states that the primary containment instrument gas system is a mechanical system designed to provide a supply of instrument gas of suitable quality and pressure for operation of pneumatic devices located inside the primary containment during normal operations.

The intended function of the primary containment instrument gas system is to provide primary containment boundary, provide motive power to safety-related components, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The primary containment instrument gas system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with NRC regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63).

LRA Table 2.3.3-14 identifies the primary containment instrument gas system component types within the scope of license renewal and subject to an AMR.

2.3.3.14.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.14, UFSAR Section 9.3.1.3, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's requests for additional information as discussed below.

In RAI 2.3.3.14-1, dated March 9, 2012, the staff noted license renewal boundary drawing LR-M-59, sheet 1, location C-6, depicts Note 5, which states, "This piping is included in scope out to the seismic anchor credited for structural support of the safety-related piping located as shown. The nonsafety-related piping beyond this anchor location is not in scope."

However, the 1-inch JCD-109 pipe continues in red, designating the piping as within the scope of license renewal for 10 CFR 54.4(a)(2) from Note 5 to the end of the pipe and including the drawing continuation marker to drawing LR-M-59, sheet 2, at location F-1. The continuation marker on sheet 2 also shows the pipe still in scope for 10 CFR 54.4(a)(2) and has another Note 5, the same as sheet 1, where the transition actually is made from red to black to indicate that the 1-inch JCD-109 pipe continuation changed to not being in scope for license renewal. For the LGS Unit 2 license renewal boundary drawing LR-M-59, sheet 3, location C-6, the 1-inch JCD-209 pipe has the same Note 5. There is also an immediate transition from red to black, which indicates that the remainder of the pipe up to and including the continuation marker is no longer within the scope of license renewal, as Note 5 indicates. There is also no duplicate Note 5 on sheet 4. The applicant was requested to clarify why the 1-inch JCD-109 pipe scope does not agree with Note 5 on license renewal boundary drawing LR-M-59, sheet 1. The applicant also was requested to clarify why there are differences in scoping between the 1-inch JCD-109 pipeline on sheets 1 and 2 and the 1-inch JCD-209 pipeline on sheets 3 and 4.

In its letter dated March 20, 2012, the applicant stated that Note 5 on license renewal boundary drawing LR-M-59, sheet 1, location C-6, will be deleted because it is a misleading reference. During the onsite IP 71002 inspection, the staff confirmed that the drawing was revised as described in response to RAI 2.3.3.14-1. The comparable scoping boundary for the LGS Unit 2 license renewal boundary drawing LR-M-59, sheet 3 will not need revision because the scoping boundary for the LGS Unit 2 1-inch JCD-209 piping does not extend onto license renewal boundary drawing LR-M-59, sheet 4.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.14-1 acceptable because the applicant revised license renewal boundary drawing LR-M-59, sheet 1, to delete Note 5. The staff also found the applicant's justification of the scoping classification difference between LGS Unit 1 and LGS Unit 2 comparable pipelines was acceptable and that no additional components were required to be brought within scope of license renewal. Therefore, the staff's concern described in RAI 2.3.3.14-1 is resolved.

In RAI 2.3.3.14-2, dated March 9, 2012, the staff noted on license renewal boundary drawing LR-M-59, sheet 3, location H-6, a line not highlighted within the scope of license renewal. However, this line is connected to a continuation marker from drawing LR-M-42, sheet 3, location A-3, which depicts the continuation marker to be highlighted in green and in scope for 10 CFR 54.4(a)(1). The applicant was requested to clarify the scoping classification of this pipe line.

In its letter dated March 20, 2012, the applicant stated that the continuation line to PDS-059-206B on license renewal boundary drawing LR-M-59, sheet 3, from LR-M-42, sheet 3, should have been shown as within the scope of license renewal for 10 CFR 54.4(a)(1). During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.3.14-2.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.14-2 acceptable because the applicant clarified the pipe section scoping classification and revised license renewal boundary drawing LR-M-59, sheet 3. Therefore, the staff's concern described in RAI 2.3.3.14-2 is resolved.

2.3.3.14.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI responses, the staff concludes the applicant appropriately identified the primary containment instrument gas system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.15 Primary Containment Leak Testing System

2.3.3.15.1 Summary of Technical Information in the Application

LRA Section 2.3.3.15 states that the primary containment leak testing system provides the ability to test the leakage of the primary containment structure, including containment penetrations, hatches, airlocks, and containment isolation valves to verify that the leakage is within specified limits as required by 10 CFR 50 Appendix J.

The intended functions of the primary containment leak testing system are to provide primary containment boundary and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.3-15 identifies the primary containment leak testing system component types within the scope of license renewal and subject to an AMR.

2.3.3.15.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.
2.3.3.15.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the primary containment leak testing system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.16 Primary Containment Ventilation System

2.3.3.16.1 Summary of Technical Information in the Application

LRA Section 2.3.3.16 states that the primary containment ventilation system removes heat from and maintains air circulation in the primary containment and provides cooling to other areas of the plant.

The intended functions of the primary containment ventilation system is to provide primary containment boundary, control combustible gas mixtures in the primary containment atmosphere, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The primary containment ventilation system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for environmental qualification (10 CFR 50.49).

LRA Table 2.3.3-16 identifies the primary containment ventilation system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.16.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.16 and UFSAR Sections 3.5.1.1.1, 6.2, 9.2.10, and 9.4.5.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. In a letter dated February 17, 2012, the staff issued RAI 2.3.3.16-1, noting that LRA Tables 2.3.3-16 and 3.3.2-16 do not contain all the component types for the primary containment ventilation system highlighted on the drawings. The tables do not list any specific components and their housing types associated with "ducting and components type" (e.g., fans and fan housing, dampers and damper housings, fire dampers and fire damper housings, filters and filter housings, heating and cooling coils), as applicable.

Therefore, the staff requested clarification on whether these component types and all other applicable component types of the system are within the scope of license renewal in accordance with 10 CFR 54.4(a) and that are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In the letter dated March 5, 2012, the applicant stated that the LGS "Ducting and Components" includes fan housings (damper housings, fire damper housings, and filter housings). This practice is consistent with the GALL Report Table IX.B definition of ducting and components, which states that ducting and components include "heating, ventilation, and air-conditioning (HVAC) components. Examples include ductwork . . . equipment frames and housing, housing supports, including housings for valves, dampers (including louvers, gravity, and fire dampers), and ventilation fans." The "Ducting and Components" component type listed in LRA Table 3.3.2-7 includes ventilation and fire damper housings and fan housings. These components are subject to an AMR. Fans, dampers, and fire dampers are active components and not subject to an AMR. Cooling coils are included in the "Heat Exchanger Components" component type. LRA Table 2.3.3-16 and Table 3.3.2-16 list the heat exchangers within the scope of license renewal and subject to an AMR. Fans and dampers are active components and are not subject to an AMR. There are no fire dampers, filters, or heaters in this system.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.16-1 acceptable. The applicant clarified the discrepancy in the listing of the primary containment ventilation system components. No new systems or components were included in the scope of license renewal as a result of this RAI response. Therefore, the staff's concern described in RAI 2.3.3.16-1 is resolved.

2.3.3.16.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the primary containment ventilation system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.17 Process Radiation Monitoring System

2.3.3.17.1 Summary of Technical Information in the Application

LRA Section 2.3.3.17 states that the process radiation monitoring system monitors the level of radioactivity of various process liquid and gas lines that can serve as discharge routes for radioactive materials. For certain systems, the process radiation monitoring system supports the prevention of an uncontrolled release of radioactive liquids, gases, and particulates by providing isolation signals to the monitored systems.

The intended functions of the process radiation monitoring system is to sense process conditions and generate signals for reactor trip or ESF actuation, provide primary containment boundary, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The process radiation monitoring system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for EQ (10 CFR 50.49).

LRA Table 2.3.3-17 identifies the process radiation monitoring system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.17.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.17, UFSAR Sections 7.6.1.1, 7.7.1.9, 11.5, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's requests for additional information as discussed below.

In RAI 2.3.3.17-1, dated March 9, 2012, the staff noted on license renewal boundary drawings LR-M-26, sheets 1 and 7, location C-2, and LR-M-26, sheet 4, location B-7, sample chambers in Detail K that are within the scope of license renewal for 10 CFR 54.4(a)(2), but are not listed in LRA Table 2.3.3-17 as a component type subject to an AMR. The applicant was requested to justify the exclusion of the sample chamber component type from LRA Table 2.3.3-17.

In its letter dated March 20, 2012, the applicant stated that the sample chambers are included in LRA Table 2.3.3-17 as a component type of "Piping, piping components, and piping elements." Additionally, as part of its RAI response, the applicant made revisions to LRA Section 3.3.2.1.17, Table 3.3.2-17, Table 3.3.1, and Table 2.3.3-17 to include the correct environments for the nonsafety-related liquid process monitor components and remove component types not applicable for the process radiation monitoring system.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.17-1 acceptable because the applicant clarified that the sample chambers are included in LRA Table 2.3.3-17 as a "Piping, piping components, and piping elements" component type. Therefore, the staff's concern described in RAI 2.3.3.17-1 is resolved.

In RAI 2.3.3.17-2, dated March 9, 2012, the staff noted on license renewal boundary drawing LR-M-26, sheet 5, location E-3, that the filter and detector housings in Detail G are within the scope of license renewal for 10 CFR 54.4(a)(1), but are not listed in Table 2.3.3-17 as a component type subject to an AMR. The applicant was requested to justify the exclusion of the filter and detector housing component types from LRA Table 2.3.3-17.

In its letter dated March 20, 2012, the applicant stated that the filters and detector housings are included in LRA Table 2.3.3-17 as a component type of "Piping, piping components, and piping elements."

Based on its review, the staff finds the applicant's response to RAI 2.3.3.17-2 acceptable because the applicant clarified that the sample chambers are located in LRA Table 2.3.3-17 as a "Piping, piping components, and piping elements" component type. Therefore, the staff's concern described in RAI 2.3.3.17-2 is resolved.

2.3.3.17.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI responses, the staff concludes the applicant appropriately identified the process radiation monitoring system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.18 Process and Post-Accident Sampling System

2.3.3.18.1 Summary of Technical Information in the Application

LRA Section 2.3.3.3.18 states that the process and post-accident sampling systems consists of the plant process sampling system and plant post-accident sampling system. The process and post-accident sampling system is designed to obtain representative samples from process streams to minimize leakage, spillage, and potential radiation exposure to operational staff.

The intended functions of the process and post-accident sampling system is to provide primary resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.3-18 identifies the process and post-accident sampling system component types within the scope of license renewal and subject to an AMR.

2.3.3.18.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.18, UFSAR Sections 9.3.2 and 11.5.5, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.3.18-1, dated March 9, 2012, the staff noted on license renewal boundary drawings LR-M-23, sheets 4 and 7, location H-4, a continuation line from the feedwater to reactor 10 CFR 54.4(a)(2) pipelines, respectively, to license renewal boundary drawings LR-M-06, sheets 3 and 6, location G-8, where the pipeline continuations are shown as not in scope of license renewal. The applicant was requested to clarify the scoping classification of these pipe lines.

In its letter dated March 20, 2012, the applicant stated that the feedwater sample lines shown on license renewal boundary drawing LR-M-06, sheets 3 and 6, are located within the turbine enclosure in an area where spatial interaction is not a concern and are correctly shown as excluded from the scope of license renewal. The sample line continuations shown on license renewal boundary drawings LR-M-23, sheets 4 and 7, terminate within the reactor enclosure in an area where spatial interaction is a concern and are correctly shown as within the scope of license renewal.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.18-1 acceptable because the applicant clarified the scoping classification of the above pipe lines. Therefore, the staff's concern described in RAI 2.3.3.18-1 is resolved.

2.3.3.18.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the process and post-accident sampling system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.19 Radwaste System

2.3.3.19.1 Summary of Technical Information in the Application

LRA Section 2.3.3.19 states that the radwaste system is a liquid, solid, and gaseous radioactive waste management system designed to process all of the radioactive, or potentially radioactive, liquid, solid, and gaseous waste generated in the operation of the plant.

The intended function of the radwaste system is to provide primary containment boundary, provide emergency heat removal from the primary containment, provide containment pressure control, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The radwaste system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for EQ (10 CFR 40.49).

LRA Table 2.3.3-19 identifies the radwaste system component types within the scope of license renewal and subject to an AMR.

2.3.3.19.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.19 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.19.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the radwaste system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.20 Reactor Enclosure Ventilation System

2.3.3.20.1 Summary of Technical Information in the Application

LRA Section 2.3.3.20 states that the reactor enclosure ventilation system provides ventilation and maintains environmental conditions to areas inside the reactor enclosure during normal plant operation. The system also maintains the reactor enclosure at a negative pressure to prevent exfiltration of potentially contaminated air, filters air exhausted from areas of potential contamination, and isolates supply and exhaust ducts of affected rooms following a high-energy line break.

The intended functions of the reactor enclosure ventilation system are to provide secondary containment boundary, maintain emergency temperature limits within areas containing safety-related components, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The reactor enclosure ventilation system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63).

LRA Table 2.3.3-20 identifies the reactor enclosure ventilation system component types within the scope of license renewal and subject to an AMR.

2.3.3.20.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.20 and UFSAR Sections 3.5.1.1.1, 9.4.2, and 9A.2.5 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant included in the scope of license renewal all components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant has identified as within the scope of license renewal to verify that the applicant has included all passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. In a letter dated February 17, 2012, the staff issued RAI 2.3.3.20-1, noting that LRA Tables 2.3.3-20 and 3.3.2-20 do not contain all the component types for the reactor enclosure ventilation system highlighted on the drawings. The tables do not list any specific components and their housing types associated with "ducting and components type" (e.g., fans and fan housing, dampers and damper housings, fire dampers and fire damper housings, filters and filter housings, heating and cooling coils, as applicable).

Therefore, the staff requested clarification as to whether these component types and all other applicable component types of the system are within the scope of license renewal in accordance with 10 CFR 54.4(a) and subject to an AMR, in accordance with 10 CFR 54.21(a)(1).

In its letter dated March 5, 2012, the applicant stated that the LGS "Ducting and Components" includes fan housings (damper housings, fire damper housings, and filter housings). This practice is consistent with the GALL Report Table IX.B definition of ducting and components, which states that ducting and components include "heating, ventilation, and air-conditioning (HVAC) components. Examples include ductwork, equipment frames and housing, housing supports, including housings for valves, dampers (including louvers, gravity, and fire dampers), and ventilation fans."

As described in LRA Sections 2.3.2.6 and 2.3.3.20, the SGTS recirculates air flow through the same path that the reactor enclosure ventilation system uses. For the purposes of license renewal evaluation, the shared ductwork and components are evaluated with SGTS.

The "Ducting and Components" listed in LRA Table 3.3.2-6 for SGTS include ventilation damper housings, fan housings, filter housings, and electric duct heater frames. The "Ducting and Components" listed in LRA Table 3.3.2-20 for the reactor enclosure ventilation system include ventilation and fire damper housings and unit cooler fan housings. These components are subject to an AMR. Cooling coils are included in LRA Table 3.3.2-20 in the "Heat Exchanger Components" component type. Fans, dampers, fire dampers, and electric duct heating coils are active components and are not subject to an AMR. Filter media are short-lived and are not subject to an AMR, as explained in the notes on drawing LR-M-76. As indicated on drawing LR-M-76 sheets 1, 2, 7, and 8, and LRA Tables 2.3.3-1 and 3.3.2-1, the steam supply to the unit heaters is evaluated with the auxiliary steam system.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.20-1 acceptable. The applicant clarified the discrepancy in the listing of the reactor enclosure ventilation system components. No new systems or components were included in the scope of license renewal as a result of this RAI response. Therefore, the staff's concern described in RAI 2.3.3.20-1 is resolved.

2.3.3.20.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the reactor enclosure ventilation system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.21 Reactor Water Cleanup System

2.3.3.21.1 Summary of Technical Information in the Application

The reactor water cleanup system is a high-pressure filtration and demineralization system designed to maintain reactor coolant purity. The reactor water cleanup system removes solid and dissolved impurities from reactor coolant, blowdown excess reactor coolant during startup, shutdown, and hot standby conditions to the main condenser, CST, or equipment drain collection tank. The system minimizes temperature gradients in the main recirculation piping and RPV during periods when the main recirculation pumps are unavailable.

The intended functions of the reactor water cleanup system are to provide primary containment boundary, sense process conditions and generate signals for reactor trip or ESF actuation, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The reactor water cleanup system is also relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48) and EQ (10 CFR 50.49).

LRA Table 2.3.3-21 identifies the reactor water cleanup system component types within the scope of license renewal and subject to an AMR.

2.3.3.21.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.21 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.21.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the reactor water cleanup system component types within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.22 Safety-Related Service Water System

2.3.3.22.1 Summary of Technical Information in the Application

LRA Section 2.3.3.22 states that the safety-related SW system is designed to remove heat from the primary containment, from areas containing ECCS equipment in the reactor enclosure, and from safety-related plant equipment. The safety-related SW system consists of the residual heat removal service water (RHRSW) system, the emergency service water (ESW) system, and the RHR heat exchanger tube corrosion monitoring subsystem.

The intended functions of the safety-related SW system are to remove residual heat from the RCS, provide heat removal from safety-related heat exchangers, provide emergency heat removal from primary containment, provide containment pressure control, maintain emergency temperature limits within areas containing safety-related components, and resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The safety-related SW system is also relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63).

LRA Table 2.3.3-22 identifies the safety-related SW system component types within the scope of license renewal and subject to an AMR.

2.3.3.22.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.22, UFSAR Sections 3.1, 3.2, 7.1.2, 7.3.1, 7.3.2, 7.4, 7.6, 9.2.2, 9.2.3, 9.2.6, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3.3.22-1, dated March 9, 2012, the staff noted on license renewal boundary drawing LR-M-13, sheet 2, locations D-2 and E-7, 1½-inch JBD-419 lines as within the scope of license renewal based on the criteria in 10 CFR 54.4(a)(2), with continuations to license renewal boundary drawing LR-M-23, sheet 7. However, the continuations of these lines on license renewal boundary drawing LR-M-23, sheet 7, are shown as not within the scope of license renewal. The applicant was requested to clarify the scoping classification of these pipe lines.

In its letter dated March 20, 2012, the applicant stated that the continuation of the 1½-inch JBD-419 lines to license renewal boundary drawing LR-M-23, sheet 7, should be within the scope of license renewal. During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.3.22-1.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.22-1 acceptable because the applicant clarified that the 1½-inch JBD-419 continuation lines to license renewal boundary drawing LR-M-23, sheet 7, are within the scope of license renewal for 10 CFR 54.4(a)(2) and revised the license renewal boundary drawing. Therefore, the staff's concern described in RAI 2.3.3.22-1 is resolved.

In RAI 2.3.3.22-2, dated March 9, 2012, the staff noted on license renewal boundary drawing LR-M-13, sheet 1, locations D-2 and D-4, that the 1½-inch JBD-319 lines are within the scope of license renewal for 10 CFR 54.4(a)(2), with continuations to and from license renewal boundary drawing LR-M-23, sheet 4. However, the continuations of these lines on drawing LR-M-23, sheet 4, are shown as not within the scope of license renewal. The applicant was requested to clarify the scoping classification of these pipe lines.

In its letter dated March 20, 2012, the applicant stated that the continuation of 1½-inch JBD-319 lines to and from the license renewal boundary drawing LR-M-23, sheet 4, should be within the scope of license renewal. During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.3.22-2.

Based on its review, the staff finds that the applicant's response to RAI 2.3.3.22-2 acceptable because the applicant clarified that the 1½-inch JBD-319 continuation lines to and from the license renewal boundary drawing LR-M-23, sheet 4, are within the scope of license renewal for 10 CFR 54.4(a)(2) and revised the license renewal boundary drawings. Therefore, the staff's concern described in RAI 2.3.3.22-2 is resolved.

2.3.3.22.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the safety-related SW system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.23 Spray Pond Pump House Ventilation System

2.3.3.23.1 Summary of Technical Information in the Application

LRA Section 2.3.3.23 states that the spray pond pump house ventilation system provides ventilation, heating, cooling, and control of environmental conditions in the spray pond pump house. The spray pond pump house ventilation system provides ventilation and cooling in the spray pond pump house under normal plant operating conditions and following DBEs, provides heating under normal plant operating conditions, and provides suitable environmental conditions for the ESW and RHRSW pumps and their accessories.

The intended function of the spray pond pump house ventilation system is to maintain emergency temperature limits within areas containing safety-related components. The spray pond pump house ventilation system also is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48) and SBO (10 CFR 50.63).

LRA Table 2.3.3-23 identifies the spray pond pump house ventilation system component types that are within the scope of license renewal and subject to an AMR.

2.3.3.23.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.23 and UFSAR Sections 3.5.1.1.1 and 9.4.7 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3.

During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has included in the scope of license renewal all components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant has included all passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. In a letter, dated February 17, 2012, the staff issued RAI 2.3.3.23-1, stating that LRA Tables 2.3.3-23 and 3.3.2-23 do not contain all the component types for the spray pond pump house ventilation system highlighted on the drawing. The tables do not list any specific components and their housing types associated with "ducting and components type" (e.g., fans and fan housing, dampers and damper housings, fire dampers and fire damper housings, filters and filter housings, heating and cooling coils, as applicable).

Therefore, the staff requested clarification on whether these component types and all other applicable component types of the system are within the scope of license renewal in accordance with 10 CFR 54.4(a) and are subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In the letter dated March 5, 2012, the applicant stated that the LGS "Ducting and Components" includes fan housings (damper housings, fire damper housings, and filter housings). This practice is consistent with the GALL Report Table IX.B definition of ducting and components, which states that ducting and components includes "heating, ventilation, and air-conditioning

(HVAC) components. Examples include ductwork . . . equipment frames and housing, housing supports, including housings for valves, dampers (including louvers, gravity, and fire dampers), and ventilation fans."

The "Ducting and Components" listed in LRA Tables 2.3.3-23 and 3.3.2-23 include ventilation and fire damper housings and fan housings. These components are subject to an AMR. There are no filters or cooling coils in the spray pond pump house ventilation system. Fans, dampers, fire dampers, and electric duct heating coils are active components and are not subject to an AMR.

During evaluation of RAI 2.3.3.23-1, the applicant determined that electric duct heater housings and a portion of the fan housings are stainless-steel and aluminum, respectively, and not carbon steel as reflected in the LRA AMR table for the spray pond pump house ventilation system. As a result of this determination, the applicant revised LRA Section 3.3.2.1.23 and LRA Tables 3.3.1 and 3.3.2-23 to include these materials. An extent of condition review of these components in the other ventilation systems confirmed that no additional changes are required to the LRA.

Based on its review, the staff finds the applicant's response to RAI 2.3.3.23-1 acceptable. The applicant clarified the discrepancy in the listing of the spray pond pump house ventilation system components. No new systems or components were included in the scope of license renewal as a result of this RAI response. Therefore, the staff's concern described in RAI 2.3.3.23-1 is resolved.

2.3.3.23.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the spray pond pump house ventilation system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.24 Standby Liquid Control System

2.3.3.24.1 Summary of Technical Information in the Application

The SLC system consists of a boron solution tank, a test water tank, three positive-displacement pumps, three explosive valves, three pump discharge relief valves, three pulsation dampeners/accumulators, a motor operated stop-check shutoff valve, and associated valves, piping, and controls. The SLC system is automatically initiated by signals from the redundant reactivity control system or manually initiated from the control room to pump a boron neutron absorber solution into the reactor if the reactor cannot be shut down with the control rods, or if suppression pool potential of hydrogen (pH) control is required to mitigate the dose consequences of a LOCA. The liquid is piped into the reactor vessel and discharged into the core by the CS line and sparger used by the HPCI system so that it mixes with the cooling water rising through the core.

The intended functions of the SLC system within the scope of license renewal include the following:

- provides emergency negative reactivity to the RCS to bring the reactor to a shutdown condition at any time in the reactor core life
- provides primary containment isolation and integrity
- maintains RCPB integrity
- provides post-LOCA pH control in the suppression pool that will minimize the potential for re-evolution of elemental iodine dissolved in the suppression pool

LRA Table 2.3.3-24 identifies the SLC system component types within the scope of license renewal and subject to an AMR.

2.3.3.24.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.24 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.24.2 Conclusion

On the basis of its review of the LRA and UFSAR the staff concludes that the applicant has appropriately identified the SLC system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.25 Traversing In-core Probe System

2.3.3.25.1 Summary of Technical Information in the Application

The traversing in-core probe (TIP) machines are comprised of a TIP detector, a drive mechanism, an indexing mechanism, and guide tubes. There are five TIP machines, each with its own group of guide tubes that correspond to a low-power range monitor (LPRM) group.

A valve system is provided with a valve on each guide tube entering the drywell. A ball valve and a cable shearing valve are mounted in the guide tubing just outside the drywell. The shear valves are actuated by explosive squibs and can cut the cable and close off the guide tube.

The intended functions of the TIP system within the scope of license renewal are to provide primary containment isolation and integrity

LRA Table 2.3.3-25 identifies the traversing in-core probe system component types within the scope of license renewal and subject to an AMR.

2.3.3.25.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.25 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.25.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the TIP system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.3.26 Water Treatment and Distribution System

2.3.3.26.1 Summary of Technical Information in the Application

LRA Section 2.3.3.26 states that the water treatment and distribution (WTD) system consists of the clarified water subsystem and the demineralized water makeup subsystem. The system is designed to provide treated makeup water to support normal plant operation. The WTD also includes the domestic water subsystem.

The intended function of the WTD system is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.3-26 identifies the water treatment and distribution system component types within the scope of license renewal and subject to an AMR.

2.3.3.25.2 Staff Evaluation

The staff reviewed LRA Section 2.3.3.26 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.3.26.2 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the WTD system component types within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4 Steam and Power Conversion Systems

LRA Section 2.3.4 identifies the steam and power conversion systems SCs subject to an AMR for license renewal. The applicant described the supporting SCs of the steam and power conversion systems in the following LRA sections:

- 2.3.4.1, "Circulating Water System"
- 2.3.4.2, "Condensate System"

- 2.3.4.3, "Condenser and Air Removal System"
- 2.3.4.4, "Extraction Steam System"
- 2.3.4.5, "Feedwater System"
- 2.3.4.6, "Main Steam System"
- 2.4.3.7, "Main Turbine System"

The staff's findings on review of LRA Sections 2.3.4.1 – 2.3.4.7 are in SER Sections 2.3.4.1 – 2.3.4.7.

Steam and Power Conversion Generic Request for Additional Information

In RAI 2.3.4-1, dated March 9, 2012, the staff noted 15 instances on drawings in which the staff could not determine the basis for the change in scoping criteria from 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2). The applicant was requested to clarify the scoping classification of the 15 10 CFR 54.4(a)(2) pipe lines.

In its response, by letter dated March 20, 2012, the applicant provided information to clarify the basis for the change in scoping criteria from 10 CFR 54.4(a)(1) to 10 CFR 54.4(a)(2) for all 15 locations. The applicant stated that piping and components that perform or support a safety-related function are within the scope of license renewal based on the criteria in 10 CFR 54.4(a)(1) and that nonsafety-related piping components within the reactor enclosure and primary containment that contain fluid are included within the scope of license renewal based on the criteria in 10 CFR 54.4(a)(2) caused by potential spacial interaction with safety-related components. The applicant stated that in five instances it determined there should not have been a transition from safety-related to nonsafety-related depicted on the scoping boundary drawings for the systems referenced in the staff's RAI. Therefore, the applicant stated that in these five instances the scoping boundary drawings would be revised to show the components referenced in the RAI as within the scope of license renewal in accordance with 10 CFR 54.4(a)(1). For the remaining 10 locations, the applicant confirmed that the scoping change depicted in the boundary drawing was correct and the components were correctly shown on the scoping drawings as within the scope license renewal in accordance with 10 CFR 54.4(a)(2).

The staff reviewed the applicant's response and found it acceptable because the applicant revised five locations on the scoping boundary drawings to properly identify safety-related components, and because the applicant confirmed that the remaining 10 locations were for nonsafety-related components and, therefore, were properly depicted as within the scope of license renewal based on the criteria in 10 CFR 54.4(a)(2). Also, during the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.4-1.

Based on its review, the staff finds the applicant's response to RAI 2.3.4-1 acceptable because the applicant clarified the 15 scoping classification changes, which included five items that were revised and corrected on their respective license renewal boundary drawings. No new component types were identified as a result of the applicant's response to the RAI. Therefore, the staff's concern described in RAI 2.3.4-1 is resolved.

2.3.4.1 Circulating Water System

2.3.4.1.1 Summary of Technical Information in the Application

LRA Section 2.3.4.1 states that the circulating water system is a closed-loop system consisting of hyperbolic natural draft cooling towers, four 25 percent capacity circulating water pumps per unit, and associated piping, valves, controls, and instrumentation designed to remove the design plant heat loads. The license renewal circulating water system includes the plant chlorination system and the Schuylkill River and Perkiomen Creek makeup systems.

The intended function of the circulating water system is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. Also, the circulating water system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.4-1 identifies the circulating water system component types within the scope of license renewal and subject to an AMR.

2.3.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.1 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.1.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the circulating water system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.2 Condensate System

2.3.4.2.1 Summary of Technical Information in the Application

LRA Section 2.3.4.2 states that the condensate system is designed to provide filtered and demineralized condensate from the condenser hotwell to the feedwater system. The condensate system also provides for the storage of condensate water for use in normal plant operations and refueling operations. The condensate system consists of the condensate (up to the filter demineralizers), condensate filter demineralizers, and condensate and refueling water storage and transfer systems.

The intended function of the condensate system is to sense process conditions and generate signals for reactor trip or engineered safety features actuation and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The condensate system also is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48).

LRA Table 2.3.4-2 identifies the condensate system component types within the scope of license renewal and subject to an AMR.

2.3.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.2 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.2.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the condensate system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.3 Condenser and Air Removal System

2.3.4.3.1 Summary of Technical Information in the Application

LRA Section 2.3.4.3 states that the condenser and air removal system is designed to condense and deaerate the exhaust steam from the main turbine during normal operation. The system has a function to provide passive holdup for leakage from the MSIVs following an accident and to isolate mechanical vacuum pump discharge upon detection of high radiation in the main steam lines.

The intended function of the condenser and air removal system is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function and for post-accident containment holdup and plateout of MSIV bypass leakage.

LRA Table 2.3.4-3 identifies the condenser and air removal system component types within the scope of license renewal and subject to an AMR.

2.3.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.3, UFSAR Sections 6.7, 10.4, 7.6, 15.4, 15.6, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.4.3-1, dated March 9, 2012, the staff noted on license renewal boundary drawings LR-M-07, sheets 1 and 3, location H-2, air inlets with screens that are within the scope of license renewal for 10 CFR 54.4(a)(2), but that are not listed in LRA Table 2.3.4-3 as a component type subject to an AMR. The applicant was requested to justify the exclusion of the air inlet with screen component type from LRA Table 2.3.4-3.

In its response, dated March 20, 2012, the applicant stated that the screens prevent foreign material from entering open pipelines and do not perform a license renewal function. The applicant stated that it will revise license renewal boundary drawings LR-M-07, sheets 1 and 3, to include a note clarifying that the screens are not within the scope of license renewal. During onsite IP 71002 inspection the staff confirmed that the drawings were revised as described in response to RAI 2.3.4.3-1.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.3-1 acceptable because the applicant clarified the purpose of the screens and revised license renewal boundary drawings LR-M-07, sheets 1 and 3, to indicate that the screens are excluded from scope of license renewal. Therefore, the staff's concern described in RAI 2.3.4.3-1 is resolved.

2.3.4.3.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the condenser and air removal system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.4 Extraction Steam System

2.3.4.4.1 Summary of Technical Information in the Application

LRA Section 2.3.4.4 states that the extraction steam system supplies steam from the high-pressure turbine, cross-around piping, moisture separator drains, and low-pressure turbine stages to the six stages of feedwater heaters.

The intended function of the extraction steam system is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function.

LRA Table 2.3.4-4 identifies the extraction steam system component types within the scope of license renewal and subject to an AMR.

2.3.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.4 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.4.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the extraction steam system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.5 Feedwater System

2.3.4.5.1 Summary of Technical Information in the Application

LRA Section 2.3.4.5 states that the feedwater system is designed to provide preheated feedwater to the RPV. The feedwater system consists of the following plant systems: heater vents and drains, feedwater, and hydrogen water chemistry.

The intended functions of the feedwater system are to provide primary containment boundary, to remove residual heat from the RCS and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The feedwater system is relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), ATWS (10 CFR 50.62), and SBO (10 CFR 50.63).

LRA Table 2.3.4-5 identifies the feedwater system component types within the scope of license renewal and subject to an AMR.

2.3.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.5 using the evaluation methodology described in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review did not identify the need for any additional information.

2.3.4.5.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the feedwater system components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.6 Main Steam System

2.3.4.6.1 Summary of Technical Information in the Application

LRA Section 2.3.4.6 states that the main steam system is designed to convey steam produced in the reactor to the main turbine and direct steam from the main steam relief valve (MSRV) discharge to the suppression pool. The main steam system includes the MSIV alternate drain pathway and the MSIV leakage control system.

The intended functions of the main steam system are to provide emergency heat removal from primary containment, provide containment pressure control for post-accident containment holdup and plateout of MSIV bypass leakage, and to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function. The main steam system is also relied upon in safety analyses or plant evaluations to perform a function that demonstrates compliance with the NRC's regulations for fire protection (10 CFR 50.48), EQ (10 CFR 50.49), and SBO (10 CFR 50.63).

LRA Table 2.3.4-6 identifies the main steam system component types within the scope of license renewal and subject to an AMR.

2.3.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.6, UFSAR Sections 3.2, 3.6, 5.2, 6.7, 10.1, 10.2, 10.4, 15.6, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified an area in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAI as discussed below.

In RAI 2.3.4.6-1, dated March 9, 2012, the staff noted on license renewal boundary drawing, LR-M-05, sheet 1, locations G-3, G-4, and G-6, that the continuation of the 1½-inch "Bearing Drain to Oily Waste" pipe from the condenser could not be found on the license renewal boundary drawings. The applicant was requested to provide the license renewal boundary for the 1½-inch "Bearing Drain to Oily Waste" pipe, and if the continuation line cannot be shown on these license renewal boundary drawings, to provide additional information describing the extent of the scoping boundary and to verify if there are additional AMR component types between the continuation and the termination of the scoping boundary. The applicant also was requested to provide additional information to clarify the change in the scoping classification, if a section of the piping changes scoping classification over the continuation.

In its letter dated March 20, 2012, the applicant described the correct license renewal scoping boundaries for the 1½-inch "Bearing Drain to Oily Waste" piping and stated that it will revise license renewal boundary drawings LR-M-05, sheets 3 and 6, and add a note describing the basis for the change. During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.4.6-1.

Based on its review the staff finds the applicant's response to RAI 2.3.4.6-1 acceptable because the applicant clarified the license renewal scoping boundary for the 1½-inch "Bearing Drain to Oily Waste" piping and provided the revised license renewal boundary drawings. Therefore, the staff's concern described in RAI 2.3.4.6-1 is resolved.

2.3.4.6.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the main steam system components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.3.4.7 Main Turbine

2.3.4.7.1 Summary of Technical Information in the Application

LRA Section 2.3.4.7 states main turbine is designed to convert the thermal energy in the steam supplied from the reactor into rotational mechanical energy. The main turbine consists of the following subsystems: main turbine, seal steam system, turbine lube oil system, electrohydraulic control system, and turbine supervisory instrumentation system.

The intended function of the main turbine is to resist nonsafety-related SSC failure that could prevent satisfactory accomplishment of a safety-related function and for post-accident containment holdup and plateout of MSIV bypass leakage.

LRA Table 2.3.4-7 identifies the main turbine component types within the scope of license renewal and subject to an AMR.

2.3.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.3.4.7, UFSAR Sections 3.2, 6.7, 10.1, 10.2, 10.3, 10.4, 15.6, and the license renewal boundary drawings using the evaluation methodology discussed in SER Section 2.3 and the guidance in SRP-LR Section 2.3. The staff's review identified areas in which additional information was necessary to complete the review of the applicant's scoping and screening results. The applicant responded to the staff's RAIs as discussed below.

In RAI 2.3.4.7-1, dated March 9, 2012, the staff noted on license renewal boundary drawing LR-M-07, sheet 2, location F-6, 1-inch HBD-359 piping within the scope of license renewal; however, the continuation on this same drawing at location B-4 shows this piping as not within the scope of license renewal. The applicant was requested to clarify the scoping classification for this pipe section.

In its letter dated March 20, 2012, the applicant clarified that the 1-inch HBD-359 piping and valve on the continuation should be within the scope of license renewal. During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.4.7-1.

Based on its review, the staff finds the applicant's response to RAI 2.3.4.7-1 acceptable because the applicant clarified the license renewal scoping boundaries of the 1-inch HBD-359 piping and revised the license renewal boundary drawings. Therefore, the staff's concern described in RAI 2.3.4.7-1 is resolved.

In RAI 2.3.4.7-2, dated March 9, 2012, the staff noted on license renewal boundary drawings LR-M-07, sheets 2 and 4, location E-7, that drain piping 1-inch HBD-359, and 1-inch HBD-459 are depicted as within the scope of license renewal for 10 CFR 54.4(a)(2). However, license renewal boundary drawings LR-M-06, sheets 2 and 5, location D-8, depict the continuation piping as not being within the scope of license renewal. The applicant was requested to clarify the scoping boundaries for the continuation piping.

In its letter dated March 20, 2012, the applicant clarified that the continuation piping and duct are within the scope of license renewal. During the onsite IP 71002 inspection, the staff confirmed that the drawings were revised as described in response to RAI 2.3.4.7-2.

Based on its review the staff finds the applicant's response to RAI 2.3.4.7-2 acceptable because the applicant clarified the license renewal boundaries of the 1-inch HBD-359 and 1-inch HBD-459 continuation piping and revised the license renewal boundary drawings. Therefore, the staff's concern described in RAI 2.3.4.7-2 is resolved.

2.3.4.7.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the main turbine components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4 Scoping and Screening Results: Structures

This section documents the staff's review of the applicant's scoping and screening results for structures. Specifically, this section discusses:

- 220 and 500 kV substations
- admin building shop and warehouse
- auxiliary boiler and lube oil storage enclosure
- circulating water pump house
- component supports commodities group
- control enclosure
- cooling towers
- diesel oil storage tank structures
- emergency diesel generator enclosure
- piping and component insulation commodity group
- primary containment
- radwaste enclosure
- reactor enclosure
- service water pipe tunnel
- spray pond and pump house
- turbine enclosure
- yard facilities

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SCs within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus allowed the staff to confirm that all structures and components meeting the scoping criteria and subject to an AMR are included.
The staff's evaluation of the information in the LRA was the same for all structures. The objective was to determine whether the applicant has identified, in accordance with 10 CFR 54.4, components and supporting structures for structures that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived SCs were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed relevant licensing basis documents, including the UFSAR, for each structure to determine whether the applicant has omitted from the scope of license renewal components with intended functions delineated under 10 CFR 54.4(a). The staff also reviewed the licensing basis documents to determine whether the LRA specified all intended functions delineated in 10 CFR 54.4(a). The staff requested additional information to resolve any omissions or discrepancies identified.

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SCs with intended functions, the staff sought to determine whether the functions are performed with moving parts or a change in configuration or properties or the SCs are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SCs were subject to an AMR, as required by 10 CFR 54.21(a)(1). The staff requested additional information to resolve any omissions or discrepancies identified.

2.4.1 220 and 500 kV Substations

2.4.1.1 Summary of Technical Information in the Application

In LRA Section 2.4.1, the applicant described the 220 kV and 500 kV substations as being composed of two separate substations physically located northwest and southeast of the power block, respectively. The purpose of the 220 kV and 500 kV substations is to provide offsite power for both LGS Units 1 and 2.

The 220 kV substation foundations consist of reinforced concrete slabs, footings, and equipment foundations on soil. The purpose of the 220 kV substation is to provide physical support, shelter, and protection to the substation equipment and the13 kV system and provide a tie-in point for the two offsite transmission lines. The offsite 220 kV system consists of two 220 kV transmission lines connected to a breaker-and-a-half design with one 220 kV-13 kV transformer. The 220 kV substation is a nonsafety-related, nonseismic structure.

The 500 kV substation foundations consist of reinforced concrete slabs, beams, grade beams, walls, piers, and footings founded on soil. The purpose of the 500 kV substation is to provide physical support, shelter, and protection to the substation equipment and 13 kV system. In addition, the 500 kV also provides a tie-in point for the three transmission lines. The offsite 500 kV system consists of three 500 kV transmission lines connected to a breaker-and-a-half design with one 500 kV-13 kV transformer. The 500 kV substation also contains the No. 4 bus tie auto transformer, which links the 220 kV substation to the 500 kV substation.

The 500 kV substation is a nonseismic structure; however, it is relied upon to provide offsite power during SBO and safe shutdown during a fire.

LRA Table 2.4-1 identifies the 220 kV and 500 kV substations component types within the scope of license renewal and subject to an AMR.

2.4.1.2 Staff Evaluation

The staff reviewed LRA Section 2.4.1 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.1.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the 220 kV and 500 kV substations components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR, in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.2 Admin Building Shop and Warehouse

2.4.2.1 Summary of Technical Information in the Application

In LRA Section 2.4.2, the applicant described the admin building shop and warehouse as an irregularly shaped multistory enclosure approximately 284 ft by 270 ft in plan area and comprised of reinforced concrete, structural steel frame and floor beams, precast concrete panels, masonry walls, commercial grade finished office interior elements, including drywall, glass, and a built up roof on metal decking. It is physically located east of and immediately adjacent to the LGS Unit 2 reactor enclosure and the LGS Unit 2 turbine enclosure.

The purpose of the admin building shop and warehouse is to provide support, shelter, and protection for site personnel and their office space, shop area, and storage in support of LGS Units 1 and 2. In addition, the structure is classified as a nonsafety-related seismic Category II structure.

LRA Table 2.4-2 identifies the admin building shop and warehouse component types within the scope of license renewal and subject to an AMR.

2.4.2.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.2.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the admin building shop and warehouse components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.3 Auxiliary Boiler and Lube Oil Storage Enclosure

2.4.3.1 Summary of Technical Information in the Application

In LRA Section 2.4.3, the applicant described the auxiliary boiler and lube oil storage enclosure as comprised of the fuel oil pump house enclosure and the auxiliary boiler pipe tunnel (also known as the machine shop pipe tunnel).

The auxiliary boiler enclosure is described as a multistory structure composed of structural steel, concrete block, and precast concrete panel. The structure is approximately 21 ft by 72 ft in plan area and is classified as a nonsafety-related seismic Category II structure.

The purpose of the auxiliary boiler enclosure is to provide physical support, shelter, and protection for the nonsafety-related auxiliary steam system components and its supporting systems.

The auxiliary boiler pipe tunnel is described as a reinforced concrete rectangular box enclosure approximately 174 inches in length and 21 feet in width and between 8 feet and 12 feet high. It is physically adjacent to the LGS Unit 2 reactor enclosure. The purpose of the auxiliary boiler pipe tunnel is to provide structural support for LGS Units 1 and 2 piping and the structures founded on the tunnel. In addition, the pipe tunnel houses safety-related and nonsafety-related piping into the power block.

The lube oil storage enclosure is described as a precast concrete panel enclosure and the exterior walls are comprised of precast concrete panels secured to a steel frame. In addition, the structure uses the southern side of the auxiliary boiler enclosure exterior masonry block wall as part of the enclosure. The single story structure is approximately 21 feet by 32 feet in plan area. The structure is classified as a nonsafety-related structure designed to commercial grade standards. The purpose of the lube oil storage enclosure is to provide physical support, shelter, and protection for the nonsafety-related equipment located inside the enclosure.

The fuel oil pump house enclosure is described as a single story, structural steel and concrete structure with precast concrete exterior panels. It is classified as a seismic Category II structure and is physically located south of the power block. The enclosure is approximately 25 feet by 40 feet in plan area. The purpose of the fuel oil pump house enclosure is to provide physical support, shelter, and protection for the nonsafety-related fuel oil transfer and fuel oil supply pumps that provide fuel to the fuel oil storage tank and feed oil to the nonsafety-related auxiliary boilers and supporting equipment.

LRA Table 2.4-3 identifies the auxiliary boiler and lube oil storage enclosure component types within the scope of license renewal and subject to an AMR.

2.4.3.2 Staff Evaluation

The staff reviewed LRA Section 2.4.3 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.3.3 Conclusion

On the basis of it review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the auxiliary boiler and lube oil storage enclosure component types within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.4 Circulating Water Pump House

2.4.4.1 Summary of Technical Information in the Application

In LRA Section 2.4.4, the applicant described the circulating water (CW) pump house as a reinforced concrete structure comprised of concrete and steel grating floors, steel roof beams, and miscellaneous steel. The CW pump house is supported by concrete fill placed on rock. The structure is approximately 42 feet by 274 feet in plan and is classified as a seismic Category II structure. The CW pump house is physically located north of the power block and south of the cooling towers.

The purpose of the CW pump house is to provide structural support; shelter and protection; access to the fire protection system fire pumps and associated piping, valves, and related equipment; and access to the circulating water system and nonsafety-related SW system pumps, piping, valves and associated equipment.

LRA Table 2.4-4 identifies the CW pump house component types within the scope of license renewal and subject to an AMR.

2.4.4.2 Staff Evaluation

The staff reviewed LRA Section 2.4.4 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.4.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the CW pump house components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.5 Component Supports Commodities Group

2.4.5.1 Summary of Technical Information in the Application

In LRA Section 2.4.5, the applicant described the component supports commodities group as consisting of structural elements and specialty components designed to transfer the load applied from an SSC to the building structural element or directly to the building foundation. The commodity group is comprised of the following supports:

- supports for ASME Class 1, 2, and 3, piping and component supports, reactor vessel skirt support anchorage, CRD support and restraints, pump supports, and the reactor vessel support ring girder and anchorage
- supports for cable trays, conduit, HVAC ducts, tube track, instrument tubing and non-ASME piping and components
- supports for HVAC system components and other miscellaneous mechanical equipment

- supports for platforms, jet impingement shields, and other miscellaneous structures
- supports for racks, panels, cabinets and enclosures for electrical equipment and instrumentation

The purpose of a support is to transfer gravity, thermal, seismic, and other lateral loads imposed on, or by the system, structure, or component to the supporting building structural element or foundation. Specialty supports such as snubbers only resist seismic forces. Vibration isolators are installed in some vibrating equipment to minimize the impact of vibration. Other support types such as guides and position stops allow displacement in a specified direction or preclude unacceptable movements and interactions.

LRA Table 2.4-5 identifies the component supports commodities group component types within the scope of license renewal and subject to an AMR.

2.4.5.2 Staff Evaluation

The staff reviewed LRA Section 2.4.5 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.5.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the component supports commodities group components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.6 Control Enclosure

2.4.6.1 Summary of Technical Information in the Application

In LRA Section 2.4.6, the applicant described the control enclosure as comprised of reinforced concrete bearing walls, slabs, foundation mat, roof, masonry walls, and structural steel. The reinforced concrete foundation is supported on bedrock. In addition, the floors and roof are constructed of reinforced concrete supported by steel beams. The roof is covered by an elastomer roofing membrane. The structure is approximately 132 feet by 62 feet in plan area and is physically located north of the seismic Class I safety-related reactor enclosures and south of the seismic Class II nonsafety-related turbine enclosure. The control enclosure is classified as a seismic Category I safety-related structure.

The purpose of the control enclosure is to provide structural support, shelter and protection to SSCs and personnel housed within the building during normal plant operations, and during and following postulated DBAs and extreme environmental conditions. In addition, the building contains the control room that provides a centralized area for control and monitoring of safety-related and nonsafety-related equipment throughout the station. The control enclosure also supports and protects both safety and nonsafety-related equipment.

LRA Table 2.4-6 identifies the control enclosure component types within the scope of license renewal and subject to an AMR.

2.4.6.2 Staff Evaluation

The staff reviewed LRA Section 2.4.6 and the UFSAR using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any SCs with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant included as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.6, the staff noted areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. By letter dated February 16, 2012, the staff issued RAI 2.4.6-1, requesting the applicant to confirm the inclusion of the "rubberized flat dumbbell-type waterstops" located at all construction joints below the maximum expected groundwater level for all safety-related enclosures, as stated in UFSAR Section 3.4.1.2 in the scope of license renewal, as applicable, and subject to an AMR per 10 CFR 54.21(a)(1)(i). In addition, in the event that the waterstops were omitted, the staff asked the applicant to justify the exclusion from the scope of license renewal.

By letter dated March 5, 2012, the applicant responded to RAI 2.4.6-1 and stated, in part, the following:

> The waterstops are included and addressed as part of the component, "Concrete: Below-Grade Exterior (Inaccessible)" that is subject to the Structures Monitoring (B.2.1.35) program or the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants (B.2.1.36) program.

In reviewing its response to RAI 2.4.6-1, the staff found that the applicant confirmed the inclusion of the waterstops within the scope of license renewal. In addition, the response also clarified the location within the LRA where the components were covered. Based on its review, the staff finds the applicant's response to RAI 2.4.6-1 acceptable because the waterstops at LGS have been included in the scope of license renewal and included in the scope of an aging management program (AMP). The staff's concern described in RAI 2.4.6-1 is resolved.

2.4.6.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the control enclosure components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.7 Cooling Towers

2.4.7.1 Summary of Technical Information in the Application

In LRA Section 2.4.7, the applicant described the cooling towers as reinforced concrete hyperbolic natural draft cooling towers that are founded on a reinforced concrete foundation supported on rock. In addition, the reinforced concrete cooling tower basin is supported on soil fill. The cooling towers are physically located north of the reactor enclosures and are classified as seismic Category II structures. The cooling tower structures are nonsafety-related and separated from safety-related SSCs such that their failure would not affect a safety-related function.

The purpose of the reinforced concrete cooling tower basins is to provide a source of cooling water for the CWS, the nonsafety-related SW system, and the fire protection system.

LRA Table 2.4-7 identifies the cooling towers component types within the scope of license renewal and subject to an AMR.

2.4.7.2 Staff Evaluation

The staff reviewed LRA Section 2.4.7 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.7.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the cooling towers components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.8 Diesel Oil Storage Tank Structures

2.4.8.1 Summary of Technical Information in the Application

In LRA Section 2.4.8, the applicant described the diesel oil storage tank structures as below-grade structures comprised of a below-grade base slab, below-grade excavated slope, structural backfill around the fuel oil tanks, and a valve pit or manhole allowing access to each tank. In addition, the tank enclosures also contain the oil unloading area concrete slab and the metal enclosure located over the valve pits. The tank enclosure is classified as a seismic Category I structure and is physically located south of the LGS Unit 1 reactor enclosure and approximately 150 feet from the emergency diesel generators. Each tank is located approximately 9 feet below grade.

The purpose of the diesel oil storage tank structures is to provide access, support, shelter, and protection to the below-grade EDG system fuel oil tanks to ensure that they remain operable during and after the design basis wind, tornadoes, floods, earthquake, and missiles.

LRA Table 2.4-8 identifies the diesel oil storage tank enclosures component types within the scope of license renewal and subject to an AMR.

2.4.8.2 Staff Evaluation

The staff reviewed LRA Section 2.4.8 and the UFSAR using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4.

During its review, the staff evaluated the structural component functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any SCs with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those SCs that the applicant included as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived SCs subject to an AMR, in accordance with the requirements of 10 CFR 54.21(a)(1).

During its review of LRA Section 2.8, the staff noted areas in which additional information was necessary to complete its review of the applicant's scoping and screening results. By letter dated February 16, 2012, the staff issued RAI 2.4.8-1, requesting the applicant to provide additional details about the metal enclosure (butler building) located over the diesel oil storage tank structures. Specifically, the information requested should justify the exclusion of the metal enclosure from the scope of license renewal and provide a detailed description on how its failure would not prevent satisfactory accomplishment of a safety-related function.

By letter dated March 5, 2012, the applicant responded to RAI 2.4.8-1 and stated, in part, the following:

> The loading on the manholes caused by a complete collapse of the metal enclosure was evaluated and determined to be bounded by the tornado missile design of the tank manholes and buried diesel oil fuel tanks. In addition, the common metal enclosure is located above the eight access manholes, with the sides and ends supported by the reinforced concrete Seismic Category I manhole walls and not by the concrete top slabs.
> Finally, the evaluation also considered the impact of a complete collapse on the fill lines and vent paths located above the Diesel Oil Storage Tank Structures and concluded that there would be no loss of any safety-related function.

In reviewing its response to RAI 2.4.8-1, the staff found that the applicant demonstrated and confirmed the adequate exclusion of the metal enclosure (butler building) from the scope of license renewal. In addition, the response also clarified that failure of this structure would not prevent satisfactory accomplishment of any safety-related function. Based on its review, the staff finds the applicant's response to RAI 2.4.8-1 acceptable because the metal enclosure (butler building) located at the diesel oil storage tank enclosures has been adequately excluded from the scope of LR and subsequent AMP. The staff's concern described in RAI 2.4.8-1 is resolved.

2.4.8.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the diesel oil storage tank structures components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.9 Emergency Diesel Generator Enclosure

2.4.9.1 Summary of Technical Information in the Application

In LRA Section 2.4.9, the applicant described the EDG enclosure as a single story multilevel structure divided into four compartments or bays, in which each bay houses an emergency diesel generator unit. Units 1 and 2, have separate EDG enclosures. Each diesel compartment or bay consists of an upper mezzanine level that contains support equipment for the diesel generator. Each enclosure is approximately 273 feet by 86 feet in plan area and is comprised of reinforced concrete walls, slabs, foundation mat, roof, masonry walls, and structural steel. The roof is reinforced concrete supported by structural steel that is protected by an elastomer roof membrane. In addition, the walls of each EDG enclosure are founded on bedrock and the base slab is supported by concrete fill placed on bedrock. The EDG enclosures are classified as seismic Category I and are physically located south of the seismic Category I reactor enclosure.

The purpose of the emergency diesel generator enclosure is to provide structural support, shelter, access control, and protection to safety-related systems, components, and structures housed within it during operation and postulated DBAs.

LRA Table 2.4-9 identifies the EDG enclosure component types within the scope of license renewal and subject to an AMR.

2.4.9.2 Staff Evaluation

The staff reviewed LRA Section 2.4.9 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.9.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the EDG enclosure components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.10 Piping and Component Insulation Commodity Group

2.4.10.1 Summary of Technical Information in the Application

In LRA Section 2.4.10, the applicant described the piping and component insulation commodity group as comprised of prefabricated blankets, modules, panels, and sheet or bulk materials engineered to fit the piping and component surfaces to be insulated. In addition, the insulation group includes metallic and nonmetallic materials.

The purpose of piping and component insulation is to improve thermal efficiency, minimize heat loads on the HVAC systems, provide for personnel protection, prevent freezing of heat traced piping, and protect against sweating of cold piping and components. In addition, insulation located in areas with safety-related equipment is designed to protect nearby safety-related equipment from overheating and maintain its structural integrity during postulated design basis seismic events.

LRA Table 2.4-10 identifies the piping and component insulation commodity group component types within the scope of license renewal and subject to an AMR.

2.4.10.2 Staff Evaluation

The staff reviewed LRA Section 2.4.10 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.10.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the piping and component insulation commodity group components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.11 Primary Containment

2.4.11.1 Summary of Technical Information in the Application

In LRA Section 2.4.11, the applicant described the primary containment as a GE BWR; specifically, a reinforced concrete Mark II type. Both LGS Units 1 and 2 have their primary containment structure completely enclosed and contained within a reactor enclosure. The reactor enclosure provides the secondary containment pressure boundary, shielding, and shelter and protection for the primary containment and the components housed within. The entire primary containment is structurally separated from the surrounding reactor enclosure, except at the base foundation slab (a reinforced concrete mat, top-lined with a carbon steel liner plate) in which a seismic gap filled with foam is provided between the two adjoining foundation slabs. Included in the boundary of the primary containment are the reinforced concrete and steel components that make up the primary containment.

The primary containments located within the reactor enclosures are classified as seismic Category I safety-related structures and are physically located south of the control enclosure and north of the emergency diesel generator enclosure.

The purpose of the primary containment is to provide a high-integrity barrier against leakage of any fission products associated with postulated accidents involving loss of coolant and to limit the release of radioactive fission products to values that ensure offsite dose rates well below 10 CFR 50.67 guideline limits. The primary containment also provides a source of water for the ECCS and for pressure suppression in the event of a LOCA. In addition, the primary containment and internal structures provide structural support to the RPV, RCSs, and other safety- and nonsafety-related SSCs housed within the primary containment.

LRA Table 2.4-11 identifies the primary containment component types within the scope of license renewal and subject to an AMR.

2.4.11.2 Staff Evaluation

The staff reviewed LRA Section 2.4.11 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.11.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the primary containment components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.12 Radwaste Enclosure

2.4.12.1 Summary of Technical Information in the Application

In LRA Section 2.4.12, the applicant described the radwaste enclosure as a multistory structure approximately 150 feet by 199 feet in plan area with above- and below-grade areas. The reinforced concrete foundation slab is supported by a layer of concrete placed on top of bedrock. The exterior and bearing walls are reinforced concrete; additionally, the exterior walls below-grade are waterproofed as necessary.

The radwaste enclosure is classified as a seismic Category IIA and designed in accordance with seismic Category I criteria, even though it is not required to protect the integrity of the RCPB, or to ensure the capability to safely shut down the reactor. Its failure would not result in potential offsite exposures comparable to the guideline exposures of 10 CFR 50.67. The structure is physically adjacent to the seismic Category I reactor enclosure.

The purpose of the radwaste enclosure and offgas enclosure is to provide structural support, shelter and protection of the recovery, processing, and temporary storage of radioactive waste during the operation of the plant. In addition, the radwaste enclosure serves to contain any effluent accidentally spilled inside the enclosure.

LRA Table 2.4-12 identifies the radwaste enclosure component types within the scope of license renewal and subject to an AMR.

2.4.12.2 Staff Evaluation

The staff reviewed LRA Section 2.4.12 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.12.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the radwaste enclosure components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.13 Reactor Enclosure

2.4.13.1 Summary of Technical Information in the Application

In LRA Section 2.4.13, the applicant described the reactor enclosure as an integral structure divided into separate LGS Unit 1 and Unit 2 reactor enclosures that share a common foundation, a common wall dividing the LGS Units 1 and 2 portions, a common refueling floor area, a common railroad airlock, a common refueling hoistway, and a common roof. The foundation for the reactor enclosure is a single integral unit consisting of continuous wall footings and spread column footings joined together by a continuous reinforced concrete mat founded on rock or on concrete fill placed on rock. The reactor enclosure is approximately 326 feet by 137 feet in plan dimension at the ground level.

The reactor enclosures are safety-related seismic Category I reinforced concrete structures and are physically located south of the control enclosure and north of the emergency diesel generator enclosure.

The purpose of the reactor enclosure and the refueling floor area are to provide secondary containment when the primary containment is in service and to provide primary containment during reactor refueling and maintenance operations when the primary containment is open. In addition, the reactor enclosure is designed to minimize release of airborne radioactive fission products to values that ensure offsite dose rates are well below 10 CFR 50.67 guideline limits, and to provide for controlled filtered elevated release of the reactor enclosure atmosphere under accident conditions.

LRA Table 2.4-13 identifies the reactor enclosure components subject to an AMR for the SCs within license renewal by component type and intended function.

2.4.13.2 Staff Evaluation

The staff reviewed LRA Section 2.4.13 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.13.2 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the reactor enclosure components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.14 Service Water Pipe Tunnel

2.4.14.1 Summary of Technical Information in the Application

In LRA Section 2.4.14, the applicant described the SW pipe tunnel as a below-grade reinforced concrete rectangular box section approximately 326 feet long, 18 feet 6 inches wide and 17 feet 6 inches high. In addition, the bottom slab is founded on concrete supported on bedrock and the roof slab extends to the grade level. Watertight doors provide below-grade access into the SW pipe tunnel from the adjacent reactor enclosure. The structure is classified as a safety-related seismic Category I structure and is physically located south of the reactor enclosure, adjacent to the west wall of the radwaste enclosure and the east wall of the auxiliary boiler and lube oil storage enclosure.

The purpose of the SW pipe tunnel is to provide structural support, shelter, and protection for LGS Units 1 and 2 for the ESW and RHR SW piping, piping components, and supporting components.

LRA Table 2.4-14 identifies the SW pipe tunnel component types within the scope of license renewal and subject to an AMR.

2.4.14.2 Staff Evaluation

The staff reviewed LRA Section 2.4.14 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.14.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the SW pipe tunnel component types within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.15 Spray Pond and Pump House

2.4.15.1 Summary of Technical Information in the Application

In LRA Section 2.4.15, the applicant described the spray pond and pump house. The spray pond is an excavated below-grade pond, sized for a water volume adequate for cooling under design basis conditions. The spray pond is comprised of the excavated spray pond, spray network piping and reinforced concrete supports, reinforced concrete overflow weir structure, reinforced concrete intake area slab, and an earthen emergency spillway. A soil-bentonite liner and a protective soil cover are placed over the entire bottom of the pond and on the soil slopes. The soil cover on the slopes, in turn, is protected by riprap and riprap bedding. The rock slopes are treated by shotcrete for protection against weathering. Rock bolts also were installed at some locations in the rock slopes as an added stability measure.

The spray pond is classified as a safety-related seismic Category I structure and is physically located about 500 feet north of the cooling towers. The purpose of the spray pond is to provide the ultimate heat sink for both units that ensures an adequate source of cooling water is available at all times for reactor shutdown, cooldown, and accident mitigation.

The spray pond pump house is a two-story reinforced concrete structure approximately 46 feet by 151 feet in plan area. It is comprised of reinforced concrete foundation slab and walls, steel floor and roof beams, and other miscellaneous structural and platform steel. A mezzanine floor composed of grating over steel beams supports the heating and ventilating equipment.

The spray pond pump house is classified as a safety-related and seismic Category I structure and is physically located on the south edge of the spray pond. The purpose of the spray pond pump house is to provide structural support, shelter and protection, and access to spray pond water for the RHRSW and ESW pumps, and associated piping, valves, and related equipment included with the safety-related SW system under postulated environmental and DBA loading conditions.

LRA Table 2.4-15 identifies the spray pond and pump house component types within the scope of license renewal and subject to an AMR.

2.4.15.2 Staff Evaluation

The staff reviewed LRA Section 2.4.15 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.15.3 Conclusion

Based on its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the spray pond and pump house components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.16 Turbine Enclosure

2.4.16.1 Summary of Technical Information in the Application

In LRA Section 2.4.16, the applicant described the turbine enclosure as a steel-framed, reinforced concrete structure enclosed with precast concrete panels above grade. It is a multistory structure approximately 170 feet by 630 feet in plan area and has reinforced concrete footings and a foundation mat supported on bedrock. In addition, seismic separation gaps are provided at the interface of the turbine enclosure with the reactor, control, and radwaste enclosures.

The turbine enclosure is physically located north of the other powerblock enclosures (radwaste enclosure, reactor enclosure, and control enclosure) and is classified as a seismic Category II nonsafety-related structure.

LRA Table 2.4-16 identifies the turbine enclosure component types within the scope of license renewal and subject to an AMR.

2.4.16.2 Staff Evaluation

The staff reviewed LRA Section 2.4.16 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.16.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the turbine enclosure components within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.4.17 Yard Facilities

2.4.17.1 Summary of Technical Information in the Application

In LRA Section 2.4.17, the applicant described the yard facilities as comprised of the tank foundations and dikes, trenches, light poles, transmission towers, fire hose cart and storage cart foundations, manholes, valve pits and duct banks, railroad bridge, transformer foundations and dikes, yard drainage system, miscellaneous yard structures, and meteorological towers.

The purpose of the yard facilities is to provide structural support, shelter, and protection for safety-related and nonsafety-related components and commodities, including components credited for fire protection and SBO. Dikes surrounding condensate storage and refueling water storage tanks are designed to contain and prevent radioactive effluent from reaching the surface waters.

LRA Table 2.4-17 identifies the yard facilities' component types within the scope of license renewal and subject to an AMR.

2.4.17.2 Staff Evaluation

The staff reviewed LRA Section 2.4.17 using the evaluation methodology described in SER Section 2.4 and the guidance in SRP-LR Section 2.4. The staff's review did not identify the need for any additional information.

2.4.17.3 Conclusion

On the basis of its review of the LRA and UFSAR, the staff concludes that the applicant has appropriately identified the yard facilities' component types within the scope of license renewal, as required by 10 CFR 54.4(a). The staff also finds that the applicant has adequately identified the system components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.5 Scoping and Screening Results: Electrical

This section documents the staff's review of the applicant's scoping and screening results for electrical and instrumentation and control systems. Specifically, this section discusses electrical and I&C component commodity groups

In accordance with the requirements of 10 CFR 54.21(a)(1), the applicant must list passive, long-lived SSCs within the scope of license renewal and subject to an AMR. To verify that the applicant properly implemented its methodology, the staff's review focused on the implementation results. This focus allowed the staff to confirm that there were no omissions of electrical and I&C system components that meet the scoping criteria and are subject to an AMR.

The staff's evaluation of the LRA information was the same for all electrical and I&C systems. The objective was to determine whether the applicant has identified, in accordance with 10 CFR 54.4, components and supporting structures for electrical and I&C systems that appear to meet the license renewal scoping criteria. Similarly, the staff evaluated the applicant's screening results to verify that all passive, long-lived components were subject to an AMR in accordance with 10 CFR 54.21(a)(1).

In its scoping evaluation, the staff reviewed the applicable LRA sections and the applicant's RAI response, focusing on components that have not been identified as within the scope of license renewal. The staff reviewed the UFSAR for each electrical and I&C system to determine whether the application has omitted, from the scope of license renewal, components with intended functions delineated under 10 CFR 54.4(a).

After its review of the scoping results, the staff evaluated the applicant's screening results. For those SSCs with intended functions, the staff sought to determine whether the functions are performed with moving parts or a change in configuration or properties or the SSCs are subject to replacement after a qualified life or specified time period, as described in 10 CFR 54.21(a)(1). For those meeting neither of these criteria, the staff sought to confirm that these SSCs were subject to an AMR, as required by 10 CFR 54.21(a)(1).

2.5.1 Electrical and Instrumentation and Controls Commodity Groups

2.5.1.1 Summary of Technical Information in the Application

LRA Section 2.5 describes the electrical and I&C systems. The scoping method considers all electrical and I&C systems, including components in the recovery path for loss of offsite power in the event of an SBO. The scoping method includes identifying the electrical I&C systems and their design functions and reviewing them against criteria contained in 10 CFR 54.4. The electrical and I&C components identified to be within the scope of license renewal have been grouped by the applicant into component commodity groups. The applicant has applied the screening criteria in 10 CFR 54.21 (a)(1)(i) and 10 CFR 54.21 (a)(1)(ii) to this list of component commodity groups to identify those that perform their intended functions without moving parts or without a change in configuration or properties and to remove the component commodity groups subject to replacement based on a qualified life or specified time period. The following list identifies the component commodity groups subject to an AMR and their intended functions:

- cable connections (metallic parts) – electrical continuity
- fuse holders: metallic clamps – electrical continuity

- high-voltage insulators – insulate (electrical)
- insulation material for electrical cables and connections – insulate (electrical)
- MEB – electrical continuity, insulate (electrical), shelter, protection
- switchyard bus and connections – electrical continuity
- transmission conductors and connectors – electrical continuity

2.5.1.2 Staff Evaluation

The staff reviewed LRA Section 2.5 and UFSAR Chapters 7 and 8 using the evaluation methodology described in SER Section 2.5 and the guidance in SRP-LR Section 2.5, "Scoping and Screening Results: Electrical and Instrumentation and Controls Systems." During its review, the staff evaluated the system functions described in the LRA and UFSAR to verify that the applicant has not omitted from the scope of license renewal any components with intended functions delineated under 10 CFR 54.4(a). The staff then reviewed those components that the applicant identified as within the scope of license renewal to verify that the applicant has not omitted any passive and long-lived components subject to an AMR in accordance with the requirements of 10 CFR 54.21(a)(1).

General Design Criteria 17 of Appendix A to 10 CFR Part 50 requires electric power from the transmission network to the onsite electric distribution system to be supplied by two physically independent circuits to minimize the likelihood of their simultaneous failure. In addition, the staff noted that the guidance provided by letter dated April 1, 2002, "Staff Guidance on Scoping of Equipment Relied on To Meet the Requirements of the Station Blackout Rule (10 CFR 50.63) for License Renewal (10 CFR 54.4(a)(3))," was later incorporated in SRP-LR Section 2.5.2.1.1, which stated the following:

> Both the offsite and onsite power systems are relied upon to meet the requirements of the SBO Rule. This includes the following:
>
> - The onsite power system meeting the requirements under 10 CFR 54.4(a)(1) (safety-related systems)
> - Equipment that is required to cope with an SBO (e.g., alternate ac power sources) meeting the requirements under 10 CFR 54.4(a)(3)
> - The plant system portion of the offsite power system that is used to connect the plant to the offsite power source meeting the requirements under 10 CFR 54.4(a)(3). The electrical distribution equipment out to the first circuit breaker with the offsite distribution system (i.e., equipment in the switchyard). This path typically includes the circuit breakers that connect to the offsite system power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical distribution system, and the associated control circuits and structures. However, the staff's review is based on the plant-specific current licensing basis, regulatory requirements, and offsite power design configurations.
>
> For purposes of the license renewal rule, the staff has determined that the plant system portion of the offsite power system that is used to connect the plant to the offsite power source should be included within the scope of the rule. This path typically includes switchyard circuit breakers that connect to the offsite system

power transformers (startup transformers), the transformers themselves, the intervening overhead or underground circuits between circuit breaker and transformer and transformer and onsite electrical system, and the associated control circuits and structures. Ensuring that the appropriate offsite power system long-lived passive SSCs that are part of this circuit path are subject to an AMR will assure that the bases underlying the station blackout (SBO) requirements are maintained over the period of extended license.

In RAI 2.5-1, dated February 16, 2012, the staff requested the applicant to confirm if the control circuits and structures associated with the switchyard circuit breakers used to supply the SBO recovery paths are within the scope of license renewal. The applicant responded to RAI 2.5-1 by letter dated March 5, 2012, stating that the circuit breaker control circuits are included in the scoping of electrical systems and components for SBO and also are part of the electrical commodities for the recovery path. Also, the applicant stated that the switchyard circuit breaker structures are included in the scope of license renewal. The staff reviewed the applicant's March 5, 2012, letter and the LRA, and confirmed that the applicant included the control circuits and structures, associated with the switchyard circuit breakers, within the scope of license renewal.

The applicant included the circuits between the plant electrical distribution system and the electrical transmission network up to and including the circuit breakers between the switchyard bus and the offsite transmission lines. The switchyard bus and connections, transmission conductors and connectors, high-voltage insulators, substation structures and supports, inaccessible power cables, MEB, insulation material for electrical cables and connections, and cable connections (metallic parts) are within the scope of license renewal. Consequently, the staff concludes that the scoping is consistent with the guidance issued April 1, 2002, and later incorporated into SRP-LR Section 2.5.2.1.1.

The applicant did not include cable tie wraps and uninsulated grounding conductors in the component groups subject to an AMR because it determined that the cable tie wraps and the uninsulated grounding conductors do not perform any license renewal functions. The staff reviewed the UFSAR and found that cable tie wraps and uninsulated grounding conductors do not meet any of the criteria in 10 CFR 54.4(a) and, therefore, are not within the scope of license renewal. Therefore, the staff concludes that the exclusion of cable tie wraps and uninsulated grounding conductors from the component groups subject to an AMR is acceptable.

2.5.1.3 Conclusion

On the basis of its review of the LRA, UFSAR, and the RAI response, the staff concludes the applicant appropriately identified the electrical and instrumentation and controls commodity groups components within the scope of license renewal, as required by 10 CFR 54.4(a), and that the applicant has adequately identified all the components subject to an AMR in accordance with the requirements stated in 10 CFR 54.21(a)(1).

2.6 Conclusion for Scoping and Screening

The staff reviewed the information in LRA Section 2, "Scoping and Screening Methodology for Identifying Structures and Components Subject to Aging Management Review and Implementation Results" and determines that the applicant's scoping and screening methodology was consistent with 10 CFR 54.21(a)(1) and the staff's positions on the treatment of safety-related and nonsafety-related SSCs within the scope of license renewal and on SCs subject to an AMR is consistent with the requirements of 10 CFR 54.4 and 10 CFR 54.21(a)(1).

On the basis of its review, the staff concludes that the applicant has adequately identified those systems and components within the scope of license renewal, as required by 10 CFR 54.4(a), and those subject to an AMR, as required by 10 CFR 54.21(a)(1).

The staff concludes that there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed licenses in accordance with the CLB and any changes to the CLB in order to comply with 10 CFR 54.21(a)(1), in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 3

AGING MANAGEMENT REVIEW RESULTS

This safety evaluation report (SER) section evaluates aging management programs (AMPs) and aging management reviews (AMRs) for Limerick Generating Station (LGS) Units 1 and 2, by the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff). In Appendix B of its license renewal application (LRA), Exelon Generation Company, LLC (Exelon or the applicant) described the 45 AMPs that it relies on to manage or monitor the aging of passive, long-lived structures and components (SCs).

In LRA Section 3, the applicant provided the results of the AMRs for those SCs identified in LRA Section 2 as within the scope of license renewal and subject to an AMR.

3.0 <u>Applicant's Use of the Generic Aging Lessons Learned Report</u>

In preparing its LRA, the applicant credited NUREG-1801, Revision 2, "Generic Aging Lessons Learned (GALL) Report," dated December 2010. The GALL Report contains the staff's generic evaluation of the existing plant programs and documents the technical basis for determining where existing programs are adequate without modification, and where existing programs should be augmented for the period of extended operation. The evaluation results documented in the GALL Report indicate that many of the existing programs are adequate to manage the aging effects for particular license renewal SCs. The GALL Report also contains recommendations on specific areas for which existing programs should be augmented for license renewal. An applicant may reference the GALL Report in its LRA to demonstrate that its programs correspond to those reviewed and approved in the report.

The purpose of the GALL Report is to provide a summary of staff-approved AMPs to manage or monitor the aging of SCs subject to an AMR. If an applicant commits to implementing these staff-approved AMPs, the time, effort, and resources for LRA review will be greatly reduced, improving the efficiency and effectiveness of the license renewal review process. The GALL Report also serves as a quick reference for applicants and staff reviewers to AMPs and activities that the staff has determined will adequately manage or monitor aging during the period of extended operation.

The GALL Report identifies: (1) systems, structures, or components (SSCs), (2) SC materials, (3) environments to which the SCs are exposed, (4) the aging effects of the materials and environments, (5) the AMPs credited with managing or monitoring the aging effects, and (6) recommendations for further applicant evaluations of aging management for certain component types.

The staff's review was in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants," and the guidance of NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), issued December 2010 and the GALL Report.

In addition to its review of the LRA, the staff conducted an onsite audit of selected AMPs, during the weeks of October 3 and October 11, 2011. The onsite audits are designed for maximum efficiency of the staff's LRA review. The applicant can respond to questions, the staff can readily evaluate the applicant's responses, the need for formal correspondence between the staff and the applicant is reduced, and the result is an improvement in review efficiency.

3.0.1 Format of the License Renewal Application

The applicant submitted an application that follows the standard LRA format agreed to by the staff and the Nuclear Energy Institute (NEI) by letter dated April 7, 2003.

The organization of LRA Section 3 parallels that of SRP-LR Chapter 3. LRA Section 3 presents AMR results information in the following two table types:

(1) Table 1s: Table 3.x.1 – where "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, and "1" indicates that this table type is the first in LRA Section 3.

(2) Table 2s: Table 3.x.2-y – where "3" indicates the LRA section number, "x" indicates the subsection number from the GALL Report, "2" indicates that this table type is the second in LRA Section 3, and "y" indicates the system table number.

The content of the previous LRAs and of the LGS Units 1 and 2 application is essentially the same. The intent of the revised format of the LRA was to modify the tables in LRA Section 3 to provide additional information that would assist in the staff's review. In its Table 1s, the applicant summarized the portions of the application that it considered to be consistent with the GALL Report. In its Table 2s, the applicant identified the linkage between the scoping and screening results in LRA Section 2 and the AMRs in LRA Section 3.

3.0.1.1 Overview of Table 1s

Each Table 1 compares in summary how the facility aligns with the corresponding tables in the SRP-LR. The tables are essentially the same as Tables 1 through 6 in the SRP-LR, except that the "Type" column has been replaced by an "Item" column and the "Item in GALL" column has been replaced by a "Discussion" column. The "Item" column is a means for the staff reviewer to cross-reference Table 2s with Table 1s. In the "Discussion" column the applicant provided clarifying information. The following are examples of information that might be contained within this column:

- further evaluation recommended - information or reference to where that information is located
- the name of a plant-specific program
- exceptions to GALL Report assumptions
- discussion of how the line is consistent with the corresponding item in the GALL Report when the consistency may not be obvious
- discussion of how the item is different from the corresponding item in the GALL Report (e.g., when an exception is taken to the GALL Report AMP)

The format of each Table 1 allows the staff to align a specific row in the table with the corresponding SRP-LR table row so that the consistency can be checked easily.

3.0.1.2 Overview of Table 2s

Each Table 2 provides the detailed results of the AMRs for components identified in LRA Section 2 as subject to an AMR. The LRA has a Table 2 for each of the systems or structures within a specific system grouping (e.g., engineered safety features (ESF), auxiliary systems). For example, the ESF group has tables specific to the core spray (CS) system, reactor core isolation cooling system, and residual heat removal system. Each Table 2 consists of nine columns:

- Component Type – The first column lists LRA Section 2 component types subject to an AMR in alphabetical order.
- Intended Function – The second column identifies the license renewal intended functions, including abbreviations, where applicable, for the listed component types. Definitions and abbreviations of intended functions are in LRA Table 2.1-1.
- Material – The third column lists the particular construction material(s) for the component type.
- Environment – The fourth column lists the environments to which the component types are exposed. Internal and external service environments are indicated with a list of these environments in LRA Tables 3.0-1, 3.0-2, and 3.0-3. LRA Table 3.0-2 states that the indoor air, uncontrolled environment encompasses the GALL Report defined environments of "air-indoor, uncontrolled," "air-indoor, uncontrolled (greater than 95 °F)," "air with steam or water leakage," "air with leaking secondary-side water and/or steam," and "condensation." LRA Table 3.0-2 also states that, for the uncontrolled indoor air environment, humidity levels of up to 100 percent are assumed, surfaces of components may be wet, and the environment may contain aggressive chemical species. The GALL Report indicates that the aging susceptibility of many materials in air depends on whether moisture is present.

  Because the applicant used the term "air-indoor, uncontrolled" to encompass several GALL Report environments, the staff could not determine whether the proper aging effects and AMPs had been identified for those AMR items exposed to the environment of "air-indoor, uncontrolled." By letter dated January 17, 2012, the staff issued RAI 3.0.2-1 requesting the applicant to (a) identify which AMR items in the LRA are exposed to an uncontrolled indoor air environment for which humidity, condensation, moisture, or other contaminants are present; and (b) if in identifying these items it is determined that the AMR items have additional aging effects requiring management, propose an AMP to manage the aging effect or state the basis for why no AMP is required.

  In its response, by letter dated February 15, 2012, the applicant stated that the information in LRA Table 3.0-2 represented potentially acceptable LGS/GALL Report environment combinations that could be used if justified; however, the table did not reflect the actual environment combinations used. The applicant also stated that that there are no AMR items in the LRA for which the environment of uncontrolled indoor air contains humidity, condensation, moisture, or contaminants; and, therefore, there are no additional aging effects requiring management. The applicant further stated that air environments that have the potential for humidity, condensation, moisture, or contaminants have been identified as "air/gas-wetted" or "air-outdoor."

The applicant revised LRA Tables 3.0-1 and 3.0-2 to reflect the actual LGS/GALL Report environment combinations used, including aligning the LGS environment of "air-indoor, uncontrolled" with the GALL Report environments of "air-indoor, uncontrolled" and "system temperature up to 288° C (550 °F)" (for closure bolting). The applicant also revised five AMR items for aluminum components and one AMR item for a galvanized steel component to correct discrepancies in the LRA in which the AMR correctly identified the environment as "air-indoor, uncontrolled", but referred to the GALL Report item that corresponded to an "air-indoor, controlled" environment. The applicant revised LRA Tables 3.2.2-6, 3.3.2-4, and 3.3.2-16 to correct the references; however, no change in aging management approach was needed.

The staff finds the applicant's response acceptable because the applicant has clarified its definition of the "air-indoor, uncontrolled" environment, such that the staff can determine whether the proper aging effects and AMPs have been identified for AMR items exposed to this environment. The staff's individual AMR item evaluations for components exposed to "air-indoor, uncontrolled" are documented in the appropriate SER sections for their associated Table 1 references. The staff's concern described in RAI 3.0.2-1 is resolved.

- Aging Effect Requiring Management (AERM) – The fifth column lists AERMs. As part of the AMR process, the applicant determined any AERMs for each combination of material and environment.
- Aging Management Programs – The sixth column lists the AMPs that the applicant uses to manage the identified aging effects.
- NUREG-1801 Item – The seventh column lists the GALL Report item(s) identified in the LRA as similar to the AMR results. The applicant compared each combination of component type, material, environment, AERM, and AMP in LRA Table 2 with the GALL Report items. If there are no corresponding items in the GALL Report, the applicant leaves the column blank to identify the AMR results in the LRA tables corresponding to the items in the GALL Report tables.
- Table 1 Item – The eighth column lists the corresponding summary item from LRA Table 1. If the applicant identifies in each LRA Table 2 AMR results consistent with the GALL Report, the Table 1 item summary number should be listed in LRA Table 2. If there is no corresponding item in the GALL Report, Column 8 is left blank. In this manner, the information from the two tables can be correlated.
- Notes – The ninth column lists the corresponding notes used to identify how the information in each Table 2 aligns with the information in the GALL Report. The notes, identified by letters, were developed by an NEI work group and will be used in future LRAs. Any plant-specific notes identified by numbers provide additional information about the consistency of the item with the GALL Report.

3.0.2 Staff's Review Process

The staff conducted three types of evaluations of the AMRs and AMPs:

(1) For items that the applicant stated are consistent with the GALL Report, the staff conducted either an audit or a technical review to determine consistency.

(2) For items that the applicant stated are consistent with the GALL Report with exceptions, enhancements, or both, the staff conducted either an audit or a technical review of the item to determine consistency. In addition, the staff conducted a technical review of the applicant's technical justifications for the exceptions or the adequacy of the enhancements.

The SRP-LR states that an applicant may take one or more exceptions to specific GALL Report AMP elements; however, any exception to the GALL Report AMP should be described and justified. Therefore, the staff considers exceptions as being portions of the GALL Report AMP that the applicant does not intend to implement.

In some cases, an applicant may choose an existing plant program that does not meet all the program elements defined in the GALL Report AMP. However, the applicant may make a commitment to augment the existing program to satisfy the GALL Report AMP before the period of extended operation. Therefore, the staff considers these augmentations or additions to be enhancements. Enhancements include, but are not limited to, activities needed to ensure consistency with the GALL Report recommendations. Enhancements may expand, but not reduce, the scope of an AMP.

(3) For other items, the staff conducted a technical review to verify conformance with 10 CFR 54.21(a)(3) requirements.

Staff audits and technical reviews of the applicant's AMPs and AMRs determine whether the aging effects on SCs can be adequately managed to maintain their intended function(s) consistent with the plant's current licensing basis (CLB) for the period of extended operation, as required by 10 CFR Part 54.

3.0.2.1 Review of AMPs

For AMPs for which the applicant claimed consistency with the GALL Report AMPs, the staff conducted either an audit or a technical review to verify the claim. For each AMP with one or more exceptions, the staff evaluated each exception to determine whether the exception was acceptable and whether the modified AMP would adequately manage the aging effect(s) for which it was credited. For AMPs not evaluated in the GALL Report, the staff performed a full review to determine their adequacy. The staff evaluated the AMPs against the following 10 program elements defined in SRP-LR Appendix A:

(1) "Scope of the program" – "Scope of the program" should include the specific SCs subject to an AMR for license renewal.

(2) "Preventive actions" – "Preventive actions" should prevent or mitigate aging degradation.

(3) "Parameters monitored or inspected" – "Parameters monitored or inspected" should be linked to the degradation of the particular structure or component intended function(s).

(4) "Detection of aging effects" – "Detection of aging effects" should occur before there is a loss of structure or component intended function(s). This includes aspects such as method or technique (i.e., visual, volumetric, surface inspection), frequency, sample size, data collection, and timing of new or one-time inspections to ensure timely detection of aging effects.

(5) "Monitoring and trending" – "Monitoring and trending" should provide predictability of the extent of degradation, as well as timely corrective or mitigative actions.

(6) "Acceptance criteria" – "Acceptance criteria," against which the need for corrective action will be evaluated, should ensure that the structure or component intended function(s) are maintained under all CLB design conditions during the period of extended operation.

(7) "Corrective actions" – "Corrective actions," including root cause determination and prevention of recurrence, should be timely.

(8) "Confirmation process" – "Confirmation process" should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective.

(9) "Administrative controls" – "Administrative controls" should provide for a formal review and approval process.

(10) "Operating experience" – "Operating experience" of the AMP, including past corrective actions resulting in program enhancements or additional programs, should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the SC intended function(s) will be maintained during the period of extended operation

Details of the staff's audit evaluation of program elements (1) through (6) and (10) are documented in SER Section 3.0.3.

The staff reviewed the applicant's quality assurance (QA) program and documented its evaluations in SER Section 3.0.4. The staff's evaluation of the QA program included assessment of the "corrective actions," "confirmation process," and "administrative controls" program elements.

The staff reviewed the information on the "operating experience" program element and documented its evaluation in SER Section 3.0.3 and 3.0.5.

3.0.2.2 Review of AMR Results

Each LRA Table 2 contains information concerning whether or not the AMRs identified by the applicant align with the GALL Report AMRs. For a given AMR in a Table 2, the staff reviewed the intended function, material, environment, AERM, and AMP combination for a particular system component type. Items in Column 7 of the LRA, "NUREG-1801 Volume 2 Item," correlate to an AMR combination as identified in the GALL Report. A blank in Column 7 indicates that the applicant was unable to identify an appropriate correlation in the GALL Report. The staff also conducted a technical review of combinations not consistent with the GALL Report. The next column, "Table 1 Item," refers to a number indicating the correlating row in Table 1.

For component groups evaluated in the GALL Report for which the applicant claimed consistency and for which it does not recommend further evaluation, the staff's review determined whether the plant-specific components of these GALL Report component groups were bounded by the GALL Report evaluation.
The applicant noted for each AMR item how the information in the tables aligns with the information in the GALL Report. The staff audited those AMRs with notes A through E indicating how the AMR is consistent with the GALL Report.

Note A indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. The staff audited these items to verify consistency with the GALL Report and validity of the AMR for the site-specific conditions.

Note B indicates that the AMR item is consistent with the GALL Report for component, material, environment, and aging effect. In addition, the AMP takes some exceptions to GALL Report AMP. The staff audited these items to verify consistency with the GALL Report and confirmed that the identified exceptions to GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note C indicates that the component for the AMR item, although different from the GALL Report, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP is consistent with the GALL Report AMP. This note indicates that the applicant was unable to find a listing of some system components in the GALL Report; however, the applicant identified in the GALL Report a different component with the same material, environment, aging effect, and AMP as the component under review. The staff audited these items to verify consistency with the GALL Report. The staff also determined whether the AMR item of the different component was applicable to the component under review and whether the AMR was valid for the site-specific conditions.

Note D indicates that the component for the AMR item, although different from, is consistent with the GALL Report for material, environment, and aging effect. In addition, the AMP takes some exceptions to the GALL Report AMP. The staff audited these items to verify consistency with the GALL Report. The staff confirmed whether the AMR item of the different component was applicable to the component under review and whether the identified exceptions to GALL Report AMPs have been reviewed and accepted. The staff also determined whether the applicant's AMP was consistent with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

Note E indicates that the AMR item is consistent with the GALL Report for material, environment, and aging effect, but credits a different AMP. The staff audited these items to verify consistency with the GALL Report. The staff also determined whether the credited AMP would manage the aging effect consistently with the GALL Report AMP and whether the AMR was valid for the site-specific conditions.

3.0.2.3 UFSAR Supplement

Consistent with the SRP-LR for the AMRs and AMPs that it reviewed, the staff also reviewed the updated final safety analysis report (UFSAR) supplement, which summarizes the applicant's programs and activities for managing aging effects for the period of extended operation, as required by 10 CFR 54.21(d).

3.0.2.4 Documentation and Documents Reviewed

In its review, the staff used the LRA, LRA supplements, the SRP-LR, and the GALL Report.

During the onsite audit, the staff also examined the applicant's justifications to verify that the applicant's activities and programs will adequately manage the effects of aging on SCs. The staff also conducted detailed discussions and interviews with the applicant's license renewal project personnel and others with technical expertise relevant to aging management.

3.0.3 Aging Management Programs

SER Table 3.0.3-1 presents the AMPs credited by the applicant and described in LRA Appendix B. The table also indicates the GALL Report AMP with which the applicant claimed consistency, if the program is a new or existing AMP and the section of this SER in which the staff's evaluation of the program is documented.

Table 3.0.3-1 Aging Management Programs

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)	Existing	Consistent	XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	3.0.3.1.1
Water Chemistry (B.2.1.2)	Existing	Consistent	XI.M2, "Water Chemistry"	3.0.3.1.2
Reactor Head Closure Stud Bolting (B.2.1.3)	Existing	Consistent with exception	XI.M3, "Reactor Head Closure Stud Bolting."	3.0.3.1.3
BWR Vessel ID Attachment Welds (B.2.1.4)	Existing	Consistent	XI.M4, "BWR Vessel ID Attachment Welds"	3.0.3.1.4
BWR Feedwater Nozzle (B.2.1.5)	Existing	Consistent	XI.M5, "BWR Feedwater Nozzle"	3.0.3.1.5
BWR Control Rod Drive Return Line Nozzle (B.2.1.6)	Existing	Consistent with enhancement	XI.M6, "BWR Control Rod Drive Return Line Nozzle"	3.0.3.2.1
BWR Stress Corrosion Cracking (B.2.1.7)	Existing	Consistent	XI.M7, "BWR Stress Corrosion Cracking"	3.0.3.1.6
BWR Penetrations (B.2.1.8)	Existing	Consistent	XI.M8, "BWR Penetrations"	3.0.3.1.7
BWR Vessel Internals (B.2.1.9)	Existing	Consistent with enhancements	XI.M9, "BWR Vessel Internals"	3.0.3.2.2
Flow-Accelerated Corrosion (B.2.1.10)	Existing	Consistent	XI.M17, "Flow-Accelerated Corrosion."	3.0.3.1.8
Bolting Integrity (B.2.1.11)	Existing	Consistent with enhancements	XI.M18, "Bolting Integrity"	3.0.3.2.3
Open-Cycle Cooling Water System (B.2.1.12)	Existing	Consistent with enhancements	XI.M21, "Open-Cycle Cooling Water System"	3.0.3.2.4
Closed Treated Water Systems (B.2.1.13)	Existing	Consistent with enhancements	XI.M21A, "Closed Treated Water Systems"	3.0.3.2.5

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.14)	Existing	Consistent with enhancement	XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	3.0.3.2.6
Compressed Air Monitoring (B.2.1.15)	Existing	Consistent with enhancement	XI.M24, "Compressed Air Monitoring"	3.0.3.1.9
BWR Reactor Water Cleanup System (B.2.1.16)	Existing	Consistent	XI.M25, "BWR Reactor Water Cleanup System"	3.0.3.1.10
Fire Protection (B.2.1.17)	Existing	Consistent with enhancements	XI.M26, "Fire Protection"	3.0.3.2.7
Fire Water System (B.2.1.18)	Existing	Consistent with enhancements	XI.M27, "Fire Water System"	3.0.3.2.8
Aboveground Metallic Tanks (B.2.1.19)	Existing	Consistent with enhancements	XI.M29, "Aboveground Metallic Tanks"	3.0.3.2.9
Fuel Oil Chemistry (B.2.1.20)	Existing	Consistent with enhancements	XI.M30, "Fuel Oil Chemistry"	3.0.3.2.10
Reactor Vessel Surveillance (B.2.1.21)	Existing	Consistent	XI.M31, "Reactor Vessel Surveillance"	3.0.3.1.11
One-Time Inspection (B.2.1.22)	New	Consistent	XI.M32, "One-Time Inspection"	3.0.3.1.12
Selective Leaching (B.2.1.23)	New	Consistent	XI.M33, "Selective Leaching of Materials"	3.0.3.1.13
One-Time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.24)	New	Consistent	XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping"	3.0.3.1.14
External Surfaces Monitoring of Mechanical Components (B.2.1.25)	New	Consistent	XI.M36, "External Surfaces Monitoring of Mechanical Components"	3.0.3.1.15
Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)	New	Consistent	XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	3.0.3.1.16
Lubricating Oil Analysis (B.2.1.27)	Existing	Consistent	XI.M39, "Lubricating Oil Analysis"	3.0.3.1.17
Monitoring of Neutron-Absorbing Materials Other than Boraflex (B.2.1.28)	Existing	Consistent with enhancements	XI.M40, "Monitoring of Neutron-Absorbing Materials Other than Boraflex"	3.0.3.2.11
Buried and Underground Piping and Tanks (B.2.1.29)	Existing	Consistent with enhancements	XI.M41, "Buried and Underground Piping and Tanks"	3.0.3.2.12

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
ASME Code Section XI, Subsection IWE (B.2.1.30)	Existing	Consistent with enhancements	XI.S1, "ASME Code Section XI, Subsection IWE"	3.0.3.2.13
ASME Code Section XI, Subsection IWL (B.2.1.31)	Existing	Consistent with enhancement	XI.S2, "ASME Code Section XI, Subsection IWL"	3.0.3.2.14
ASME Code Section XI, Subsection IWF (B.2.1.32)	Existing	Consistent with enhancement	XI.S3, "ASME Code Section XI, Subsection IWF"	3.0.3.2.15
10 CFR Part 50, Appendix J (B.2.1.33)	Existing	Consistent	XI.S4, "10 CFR Part 50, Appendix J"	3.0.3.1.18
Masonry Walls (B.2.1.34)	Existing	Consistent with enhancements	XI.S5, "Masonry Walls"	3.0.3.2.16
Structures Monitoring (B.2.1.35)	Existing	Consistent with enhancements	XI.S6, "Structures Monitoring"	3.0.3.2.17
RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" (B.2.1.36)	Existing	Consistent with enhancements	XI.S7, "RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants"	3.0.3.2.18
Protective Coating Monitoring and Maintenance (B.2.1.37)	Existing	Consistent with enhancements	XI.S8, "Protective Coating Monitoring and Maintenance Program"	3.0.3.2.19
Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38)	New	Consistent	XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.19
Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.39)	New	Consistent	XI.E2, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	3.0.3.1.20
Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)	New	Consistent	XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements."	3.0.3.1.21
Metal Enclosed Bus (B.2.1.41)	New	Consistent	XI.E4, "Metal Enclosed Bus"	3.0.3.1.22
Fuse Holders (B.2.1.42)	New	Consistent	XI.E5, "Fuse Holders"	3.0.3.1.23
Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)	New	Consistent	XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	3.0.3.1.24

AMP (LRA Section)	New or Existing AMP	GALL Report Comparison	GALL Report AMPs	Staff's SER Section
Fatigue Monitoring (B.3.1.1)	Existing	Consistent with enhancements	X.M1, "Fatigue Monitoring"	3.0.3.2.20
Environmental Qualification (EQ) of Electric Components (B.3.1.2)	Existing	Consistent	X.E1, "Environmental Qualification (EQ) of Electric Components"	3.0.3.1.25

3.0.3.1 AMPs Consistent with the GALL Report

In LRA Appendix B, the applicant identified the following AMPs as consistent with the GALL Report:

- ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD (B.2.1.1)
- Water Chemistry (B.2.1.2)
- Reactor Head Closure Stud Bolting (B.2.1.3)
- BWR (Boiling-Water Reactor) Vessel ID Attachment Welds (B.2.1.4)
- BWR Feedwater Nozzle(B.2.1.5)
- BWR Stress Corrosion Cracking (B.2.1.7)
- BWR Penetrations (B.2.1.8)
- Flow-Accelerated Corrosion (B.2.1.10)
- Compressed Air Monitoring (B.2.1.15)
- BWR Reactor Water Cleanup System (B.2.1.16)
- Reactor Vessel Surveillance (B.2.1.21)
- One-Time Inspection (B.2.1.22)
- Selective Leaching (B.2.1.23)
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping (B.2.1.24)
- External Surfaces Monitoring of Mechanical Components (B.2.1.25)
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components (B.2.1.26)
- Lubricating Oil Analysis (B.2.1.27)
- 10 CFR Part 50, Appendix J (B.2.1.33)
- Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.38)
- Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits (B.2.1.39)
- Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.40)
- Metal Enclosed Bus (B.2.1.41)
- Fuse Holders (B.2.1.42)
- Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements (B.2.1.43)
- Environmental Qualification (EQ) of Electric Components (B.3.1.2)

3.0.3.1.1 ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD

Summary of Technical Information in the Application. LRA Section B.2.1.1 describes the existing ASME [American Society of Mechanical Engineers] Section XI Inservice Inspection (ISI), Subsections IWB, IWC, and IWD program as consistent with GALL Report AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD." It states that this program manages cracking, loss of fracture toughness, and loss of material in ASME Code Class 1, 2, and 3 piping and components within the scope of license renewal. The LRA also states that this program includes periodic visual, surface, volumetric examinations, and leakage tests of ASME Code, Class 1, 2, and 3 pressure-retaining components, including welds, pump casings, valve bodies, integral attachments, and pressure-retaining bolting.

In addition, the LRA states that indications and relevant conditions detected during examinations are evaluated in accordance with ASME Code, Section XI, Articles IWB-3000, IWC-3000, and IWD-3000. The LRA states that the program directs that repair and replacement activities be performed in accordance with ASME Code, Section XI, IWA-4000. The LRA further states that this program is updated during each successive 120-month (10-year) inspection interval to comply with the requirements of the ASME Code, Section XI, Subsections IWB, IWC, and IWD, edition and addenda in accordance with 10 CFR 50.55a, subject to prior approval of the edition and addenda by the NRC.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff also reviewed the plant conditions to determine if they are bounded by the conditions for which the GALL Report was evaluated.

The staff compared elements 1-6 of the applicant's program to the corresponding elements of GALL Report AMP XI.M1. As discussed in the Audit Report, the staff confirmed that each element of the applicant's program is consistent with the corresponding element of GALL Report AMP XI.M1.

The "detection of aging effects" program element in GALL Report AMP XI.M1 states that ASME Code, Section XI, Table IWB-2500-1, is used to determine the examination of Categories B-F and B-J welds. The staff noted that the applicant implemented risk-informed inservice inspection (RI-ISI) with Examination Category R-A instead of Categories B-F and B-J for the current 10-year ISI interval as approved by the NRC. The RI-ISI provides alternate inspection requirements for a subset of ASME Code Class 1 piping welds. The staff noted that the use of RI-ISI is only approved for the current 10-year ISI interval. Future implementation of RI-ISI is subject to the NRC approval in accordance to 10 CFR 50.55a for each subsequent 10-year ISI interval, including the period of extended operation. The staff confirmed during the onsite audit that the applicant's ISI program plan calls for a review of the RI-ISI implementation for future inspection intervals. The staff finds this acceptable because the applicant will have to seek NRC approval for use of this RI-ISI relief request for future inspection intervals.

The staff noted that the applicant updates its program every 10 years (120 months) to the latest ASME Code, Section XI, as approved by the NRC before the start of the inspection interval. Both LGS Unit 1 and LGS Unit 2 are in their third 10-year ISI interval, which began on February 1, 2007. The current ASME Code of record for both LGS Unit 1 and LGS Unit 2 is the 2001 Edition through the 2003 Addenda.

Based on its audit, the staff finds that elements 1-6 of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program are consistent with the corresponding program elements of GALL Report AMP XI.M1 and, therefore, acceptable.

Operating Experience. LRA Section B.2.1.1 summarizes operating experience related to the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. The applicant indicated that this program is based on the ASME Code, Section XI, Subsections IWB, IWC, and IWD, which is based on industrywide operating experience, research data, and technical evaluations. The applicant stated that plant-specific examples are documented in its ISI summary reports and in the corrective action program (CAP) records. The staff sampled inspection results from the current 10-year interval ISI summary reports. For example, the ISI program examinations identified multiple pinhole leaks and pipe wall thinning in its emergency service water (ESW) piping and residual heat removal service water (RHRSW) system piping in both LGS Unit 1 and LGS Unit 2. The applicant performed numerous analyses and attributed the pinhole leaks and wall thinning to initial operation with untreated water, which established significant corrosion cells. As part of the corrective actions, the applicant has improved its water treatment to eliminate the root cause. In addition, as part of the ISI repair and replacement, the applicant has replaced some of the degraded piping with more corrosion-resistant stainless steel piping. The evaluation of the operating experience related to the applicant's ESW and RHRSW system piping is further discussed in the staff's review of LRA Section B.2.1.12, "Open Cycle Cooling Water System," as documented in Section 3.0.3.2.4 of this SER.

The staff reviewed the applicant's ISI summary reports submitted for the current and previous 10-year ISI intervals for both LGS units to verify that the applicant's implementation of the program was effective in detecting, trending, and correcting those aging effects for which the program was credited. The staff's review of these ISI summary reports did not reveal any evidence that would demonstrate that the program was ineffective in detecting the aging effects this program manages.

The applicant stated that its operating experience is consistent with industry operating experience. It cited multiple examples in which examinations performed per the ISI program have been effective in detecting flaws, evaluating flaws, and directing repair and replacement activities. The applicant further indicated that it will use its site-specific corrective action program and an ongoing review of industry operating experience to ensure that the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program remains effective in managing the identified aging effects. The staff reviewed the operating experience information in the application and information obtained during the audit to determine whether the applicant reviewed the applicable aging effects, industry, and plant-specific operating experience. As discussed in the Audit Report, the staff also conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff did not find operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.1 provides the UFSAR supplement for the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. The staff reviewed this UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.0-1. The staff determines that the information in the UFSAR supplement is an adequate summary description of the program, as required by 10 CFR 54.21(d).

Conclusion. On the basis of its audit and review of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, the staff finds all program elements consistent with the GALL Report. 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).

3.0.3.1.2 Water Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.2 describes the existing Water Chemistry program as consistent with GALL Report AMP XI.M2, "Water Chemistry." The LRA states that this program uses the guidance of the Boiling Water Reactor Vessel and Internals Project (BWRVIP)-190, "BWR Water Chemistry Guidelines – 2008 Revision," and addresses the reactor vessel, reactor internals, piping components, heat exchangers, and tanks exposed to treated water environments. The LRA also states that this program manages loss of material, cracking, and reduction of heat transfer through monitoring, trending, and controlling of the chemical environments for detrimental contaminants in associated systems. The LRA further states that this program does not detect aging effects, but components located in stagnant or low flow areas, where water chemistry programs may not be effective, will be inspected as part of the One-Time Inspection program to verify proper chemistry control and aging management.

Staff Evaluation. During its audit, 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.M2. Based on its audit of the Water Chemistry program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M2.

Operating Experience. LRA Section B.2.1.2 summarizes operating experience related to the Water Chemistry program. The LRA described an occurrence in 2003 in which the stability of insoluble iron for LGS Unit 2 was less than the values for LGS Unit 1. The LRA stated that a common-cause analysis determined that the differences between the units' sample line diameters and lengths had caused the discrepancy because of the effects of velocity and flow rates on particulate suspension. The LRA described changes made to the sampling practices and stated this illustrated the effectiveness of the program to identify and resolve issues through monitoring and implementing corrective actions.

The LRA also described an occurrence in 2006 related to increasing trends in reactor water conductivity and chlorides following a refueling outage, which exceeded chemistry action levels for a short period of time (i.e., less than the limiting condition for operation). The LRA stated that a root cause investigation determined that the excursion may have been because of the use of a chlorinated solvent. After evaluating various aspects, the LRA recommended that noble metals be reapplied because of the potential for crack flanking of the noble metal coating. The LRA concluded that this illustrated the effectiveness of the program to analyze the extent of chemistry excursions and to evaluate the effects of these deviations.

The staff reviewed operating experience information in the application and during the audit to determine if the applicant reviewed the applicable aging effects and industry and plant-specific operating experience. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine if the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.2 provides the UFSAR supplement for the Water Chemistry program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1 and noted that, although the supplement stated that the program is based on BWRVIP Water Chemistry Guidelines, it did not state that the program is based on BWRVIP-190, which is the 2008 revision. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its UFSAR supplement. By letter dated January 17, 2012, the staff issued RAI B.2.1.2-1, requesting the applicant to include BWRVIP-190 in its UFSAR supplement for this program.

In its response, provided by letter dated February 15, 2012, the applicant revised LRA Section A.2.1.2 to state that the program is based on the guidelines of BWRVIP-190. The staff also noted that similar information was included in the new LRA Appendix C, "Response to BWRVIP License Renewal Applicant Action Items," item BWRVIP-74-A(6). The staff finds the applicant's response acceptable because the description of the Water Chemistry program in the UFSAR supplement includes BWRVIP-190, which will ensure the licensing basis will be adequately maintained during the period of extended operation. Therefore, the UFSAR supplement for the Water Chemistry program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.2.1.2-1 is resolved.

The staff finds that the information in the UFSAR supplement, as amended by letter dated February 15, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the Water Chemistry program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. The staff also 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 reviewed the UFSAR supplement for this AMP and further

concludes that it provides an adequate summary description of the program, as required by 10 CFR 54.21(d).

3.0.3.1.3 Reactor Head Closure Stud Bolting

Summary of Technical Information in the Application. LRA Section B.2.1.3 describes the existing Reactor Head Closure Stud Bolting program as consistent with GALL Report AMP XI.M3, "Reactor Head Closure Stud Bolting."

The LRA states that the Reactor Head Closure Stud Bolting program is an existing condition monitoring and preventive program that provides for ASME Code, Section XI, inspections of reactor head closure studs, associated nuts, bushings, flange threads, and washers for cracking and loss of material. The LRA also states that the program manages these aging effects in air with reactor coolant leakage environment. The LRA further states that the program is based on the examination and inspection requirements specified in the ASME Code, Section XI, Subsection IWB, Table IWB-2500-1, and preventive measures described in NRC Regulatory Guide (RG) 1.65, "Materials and Inspections for Reactor Vessel Closure Studs." The LRA states that the inspections monitor for cracking, loss of material, and coolant leakage. The LRA also states that the flange threads and studs receive a volumetric examination and the surfaces of nuts and washers are inspected using visual VT-1 examination. The LRA further states that all pressure-retaining boundary components in Examination Category B-P receive visual VT-2 examination during the system leakage and the system hydrostatic tests.

In addition, the LRA states that the program includes the preventive measures to mitigate cracking described in RG 1.65, which includes the use of approved corrosion inhibitors and lubricants. The LRA also stated that the reactor head closure studs, nuts, bushings, flange threads, and washers are fabricated with approved materials and surface-treated with an acceptable phosphate coating to inhibit corrosion and reduce stress corrosion cracking (SCC) and intergranular stress corrosion cracking (IGSCC). The applicant further stated that the reactor head closure studs are constructed of ASME Code SA540 Grade B24, Class 3 material, which has a maximum tensile strength level less than 170 ksi.

Staff Evaluation. During its audit, 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.M3. For the applicant's "preventive actions" program element, the staff noted a potential exception to GALL Report AMP. Therefore, the staff issued an RAI, as discussed below.

The "preventive actions" program element in GALL Report AMP XI.M3 lists preventive measures that can reduce the potential for SCC and IGSCC. These measures, among others, include using bolting material for closure studs that has actual measured yield strength less than 150 ksi, and using manganese phosphate or other acceptable surface treatments. During its audit, the staff noted that the applicant's onsite documentation for its reactor head closure stud bolting program indicated that some of the closure studs and nuts were manufactured from material with actual measured yield strength greater than 150 ksi. The staff also noted that the LRA AMP states that the reactor head closure stud, nut, bushing, flange thread, and washer surfaces are treated with an acceptable phosphate coating to inhibit corrosion and reduce SCC and IGSCC. However, Section 5.3.1.11 of the applicant's UFSAR indicates that a phosphate coating is only applied to threaded areas of studs and nuts and bearing areas of nuts and washers. It was not clear to the staff if closure bolting with measured yield strength greater than

150 ksi will be used during the period of extended operations and if a phosphate coating was actually applied to the applicant's flange threads as stated in the LRA.

By letter dated January 17, 2011, the staff issued RAI B.2.1.3-1, requesting the applicant to clarify if closure studs and nuts manufactured from material with actual measured yield strength greater than 150 ksi will be used during the period of extended operation. If so, the applicant was asked to justify the adequacy of the program to manage cracking because of SCC, to provide clarification if a phosphate coating was applied on the flange threads, whether the phosphate coating applied to the closure bolting components is intact, and to justify adequacy of the program if that was not the case.

Exception. By letter dated February 15, 2012, the applicant amended LRA Section B.2.1.3 and identified the use of closure studs with actual measured yield strength greater than or equal to 150 ksi as an exception to the "preventive actions" program element of GALL Report AMP XI.M3.

As part of its response, the applicant provided a table summarizing the actual measured yield and tensile strength values for LGS, Units 1 and 2 reactor head closure bolting. The applicant stated that it has revised its purchasing requirements for reactor head closure studs to ensure that any replacement studs installed in the future will have measured yield strength less than 150 ksi. Also, as part of its response on aging management for SCC, the applicant stated that its program is consistent with other aspects of preventive measures listed in GALL Report AMP XI.M3; e.g., that metal-plated stud bolting is not used and an approved stable lubricant is applied to the studs and associated hardware whenever the reactor head is installed, which does not contain molybdenum disulfide (MoS_2). The applicant stated that the volumetric ultrasonic examination (UT) method is used for the stud inspections to identify cracking. Furthermore, following each refueling outage, a system pressure test is performed to identify and correct any potential reactor coolant leaks, thus avoiding exposure of the studs to an environment conducive to SCC. The applicant stated that there have been no recordable indications identified by past examinations of reactor head closure stud bolting components over the past 10 years, indicating that the current program has been effective in managing cracking.

The staff reviewed the applicant's exception on the use of bolting material with actual measured yield strength greater than 150 ksi. As part of its review, the staff reviewed the applicant's justification for the adequacy of the AMP to manage SCC in the high-strength material. Specifically, the staff reviewed the maximum measured yield strength and tensile strength data the applicant extracted from the certified material test report for the applicant's reactor head closure studs. The staff noted that the maximum measured tensile strength of the studs ranged from 164 ksi to 169 ksi as shown below:

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

In addition, the staff noted that with the exception of four studs for LGS Unit 2, all of the average measured yield strength values for the studs are below 150 ksi. The staff also noted that a limited number of studs have average yield strength slightly exceeding 150 ksi. The staff further noted that the applicant uses stable lubricants for its reactor head closure bolting, which is an appropriate measure to mitigate or prevent SCC in the closure bolting components, consistent with the GALL Report. Moreover, the staff reviewed the most recent ISI summary reports for LGS Units 1 and 2 and confirmed that the ultrasonic examinations did not find any recordable indications for the applicant's closure studs and flange threads. Furthermore, the staff noted that VT-1 examinations also confirmed that there were no recordable indications reported for the applicant's reactor head closure nuts and washers.

Based on its review, the staff finds the exception acceptable because the program includes ultrasonic examination of each closure stud during each inspection interval, which provides reasonable assurance that SCC in closure studs can be detected and adequately managed before loss of intended function, the volumetric examinations of the closure studs have not indicated any evidence of SCC, and all of the applicant's closure studs have measured tensile strength values less than 170 ksi. In addition, the majority of the applicant's closure studs have average measured yield strength values less than 150 ksi; therefore, these components do not have significantly high susceptibility to SCC and the applicant's use of stable lubricants is an appropriate preventive measure to ensure that closure studs are protected from contaminants that could lead to SCC. Therefore, the staff's concerns regarding SCC described in RAI B 2.1.3-1 are resolved.

By the same letter dated February 15, 2012, the applicant also revised the LRA to remove the bushings and flange threads from the list of components fabricated with phosphate coating and removed bushings from the list of components the program managed. In its response to the application of a protective coating, the applicant stated that its review of the staff's RAI resulted in identifying that its design for reactor head closure stud bolting does not include bushings as stated in LRA Section B.2.1.3 and Section A.2.1.3. The applicant stated that a manganese phosphate coating was applied to the threaded areas of the studs and nuts, and bearing areas of the nuts and washers as described in the UFSAR, while a phosphate coating was not applied to the flange threads. The applicant also stated that based on recent observations by personnel performing inspections of the closure bolting components, there was no visual evidence that the manganese phosphate coating is intact. The applicant further stated that corrosion is managed effectively by the application of an approved, stable lubricant whenever the stud bolting is assembled and by periodic examinations in accordance with ASME Code requirements. The applicant also stated that there have been no recordable indications identified by the ASME Code-required examinations. The staff finds this response acceptable because the applicant has appropriately revised the LRA to be consistent with its UFSAR. The staff's concerns expressed in RAI B 2.1.3-1 about the inconsistencies the staff noted in the applicant's LRA and UFSAR are resolved.

In addition, the staff reviewed the applicant's justification of the adequacy of its program to manage the aging effects caused by corrosion in the absence of the phosphate coating on the applicant's reactor closure bolting. During its review, the staff noted that the applicant uses stable lubricants for its closure bolting, which can mitigate corrosion by precluding contact with contaminants that can cause corrosion. The staff also noted that as part of the ASME Code-required periodic examinations, the applicant performs VT-2 examination of pressure-retaining components during system leakage testing. The staff further noted that VT-1 examinations of the applicant's nuts and washers confirmed that there were no recordable indications on the applicant's closure bolting, providing confirmation that the applicant's program is effective in mitigating the aging effects of corrosion. Therefore, the staff's concerns about the integrity of the phosphate coating expressed in RAI B 2.1.3-1 are resolved.

Based on its audit, and review of the Reactor Head Closure Stud Bolting program, the staff finds that the program elements 1, 3, 4, 5, and 6, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M3. The staff also reviewed the exception associated with the "preventive actions" program element and the applicant's response to RAI 2.1.3-1. Based on its review, the staff finds the applicant's proposed AMP, with exception, is adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.3 summarizes operating experience related to the Reactor Head Closure Stud Bolting program. The applicant stated that ultrasonic examinations performed on all of the closure studs and flange threads for LGS Units 1 and 2 from 2002 to 2010 confirmed that there were no recordable indications. The applicant also stated that during the same period, VT-1 examinations performed on all of the closure washers and nuts also confirmed that there were no recordable indications. The applicant further stated that historically, inspections have found the reactor closure studs, flange threads, nuts, and washers to be in satisfactory condition. The applicant also stated that the review of the operating experience for the Reactor Head Closure Stud Bolting program did not identify an adverse trend in performance or signs of age-related degradation. Based on its operating experience review results, the applicant stated that there is confidence that continued implementation of the Reactor Head Closure Stud Bolting program will effectively identify degradation before failure during the period of extended operation.

The staff reviewed operating experience information in the application and during the audit to determine if the applicant reviewed the applicable aging effects and industry and plant-specific operating experience. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine if the applicant adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.3, as revised by letter dated February 15, 2012, provides the UFSAR supplement for the Reactor Head Closure Stud Bolting program. The staff reviewed the revised UFSAR supplement description of the program and notes that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.0-1. 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 Reactor Head Closure Stud Bolting program, the staff determines that the program elements for which the applicant claimed consistency with the GALL Report are consistent. In addition, the staff reviewed the exception and its justification and determines that the AMP, with the exception, is 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).

3.0.3.1.4 BWR Vessel Inside Diameter (ID) Attachment Welds

Summary of Technical Information in the Application. LRA Section B.2.1.4 describes the existing BWR Vessel ID Attachment Welds program as consistent with GALL Report AMP XI.M4, "BWR Vessel ID Attachment Welds."

The LRA states that the program manages the effects of cracking in the reactor vessel inside diameter (ID) attachment welds by the inspection and evaluation recommendations of BWRVIP-48-A. The program provides for mitigation of cracking through management of reactor water chemistry and monitoring for cracking through in-vessel examinations of the reactor vessel internal attachment welds. The program also manages the effects of loss of material caused by wear of the steam dryer support brackets. These inspections are implemented as part of augmented ISI requirements.

Staff Evaluation. During its audit, 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.M4.

During its audit, the staff noted that the applicant manages the effects of loss of material caused by wear of the LGS Unit 1 steam dryer support brackets by using a visual VT-3 examination as part of the BWR Vessel ID Attachment Welds program. The staff noted that loss of material is not addressed in GALL Report AMP XI.M4 or BWRVIP-48-A; therefore, it is not clear to the staff whether the VT-3 examination is an appropriate and effective inspection method to identify loss of material of the steam dryer support brackets. The staff noted that since BWRVIP-48-A does not manage wear or loss of material, the applicant has not identified the acceptance criteria for the inspections of steam dryer support brackets and associated corrective actions if the acceptance criteria are not met. By letter dated November 18, 2011, the staff issued RAI B.2.1.4-1 requesting the applicant to justify the use of a visual VT-3 examination for the steam dryer support brackets and to identify the acceptance criteria and associated corrective actions.

In its response, provided by letter dated December 7, 2011, the applicant stated that the inspection of the bracket for loss of material because of wear by visual VT-3 examination is appropriate to identify this aging effect because ASME Code Section XI, Article IWA-2213(a) indicates that visual VT-3 can be conducted to determine loose or missing parts, debris, corrosion, wear, or erosion. The staff noted that it is consistent with the "detection of aging" program element of GALL Report AMP XI.M4 that VT-3 examinations can be used to determine the general mechanical and structural condition of the components. Thus, the staff finds it is reasonable that wear or loss of material for the steam dryer support brackets can be detected with the use of VT-3 examinations.

The applicant explained that BWRVIP48-A refers to ASME Code Section XI, Subsection IWB-3520 for acceptance criteria. The staff noted that ASME Code Section XI, Subsection IWB-3520.2 provides acceptance criteria and relevant conditions that require corrective actions before continued service for VT-3, which is consistent with the "acceptance criteria" program element of the GALL Report AMP XI.M4.

The applicant also stated that corrective actions for wear conditions are performed in accordance with ASME Code Section XI, Subsection IWB-3140. The staff noted that corrective actions in ASME Code, Section XI, Subsection IWB-3143, include repair and replacement activities that are equivalent to those in ASME Code, Section XI, Subsection IWA-4000, and are also consistent with the "corrective actions" program element of GALL Report AMP XI M4. The applicant explained that other activities that have been performed for the wear conditions identified on the steam dryer support brackets included performing engineering evaluation and followup inspections during subsequent LGS Unit 1 outages to monitor and trend the wear condition in accordance with its CAP and performing extent of condition examinations for wear on LGS Unit 2 components.

The applicant stated that a CAP issue report has been initiated to revise the implementing procedure. The revision will document programmatic elements, including the use of visual VT-3 examination, acceptance criteria, and corrective actions related to the inspection of steam dryer support brackets to manage loss of material because of wear. The staff noted that the UFSAR supplement in LRA Section A.2.1.4 is also revised to include a description of how the program manages the effects of loss of material caused by wear of the steam dryer support brackets.

The staff finds the applicant's response acceptable because its inspection methodology, acceptance criteria, and corrective actions are consistent with the provision in ASME Code Section XI, which have been proven capable of detecting and managing loss of material caused by wear and the BWR Vessel ID Attachment Welds program ensures that these inspections will be conducted as part of its augmented ISI requirements. The staff's concern described in B.2.1.4-1 is resolved.

Based on its audit of the BWR Vessel ID Attachment Welds program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M4.

<u>Operating Experience</u>. LRA Section B.2.1.4 summarizes operating experience related to the BWR Vessel ID Attachment Welds program.

The applicant indicated that the examinations of LGS Units 1 and 2 vessel internal attachment welds were performed using enhanced visual techniques (EVT)-1 between the 2000 and 2009 refueling outages. The applicant stated that the examinations included all of the jet pump riser brace support pads, the feedwater sparger attachment welds, the steam dryer support bracket attachment welds, and the CS bracket attachment welds. The applicant further stated that examination of the guide rod bracket attachment welds was performed using VT-3 visual techniques and no indications were identified. Examination of the surveillance sample holder attachment welds was performed using VT-1 visual techniques and no indications were identified.
The applicant indicated re-inspection of all four LGS Unit 1 steam dryer support bracket attachment welds was performed using visual techniques in 2010 and that wear was identified on all four brackets and a condition report was generated to evaluate the wear. The indications

on three of the four brackets were considered normal wear and the wear on one of the brackets was considered notable. In accordance with the program requirements, scope expansion was defined, which included additional examinations of the steam dryer hold down brackets (on the underside of the RPV head) and the steam dryer seismic blocks (on the steam dryer support ring) during the 2010 outage. The applicant further stated that no indications were identified on the steam dryer hold down brackets.

The staff reviewed operating experience information in the application and during the audit, to determine if the applicant reviewed applicable aging effects and industry and plant-specific operating experience. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine if the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.4, as amended by letter dated December 7, 2011, provides the UFSAR supplement for the BWR Vessel ID Attachment Welds program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 BWR Vessel ID Attachment Welds program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.5 BWR Feedwater Nozzle

Summary of Technical Information in the Application. LRA Section B.2.1.5 describes the existing BWR Feedwater Nozzle program as consistent with GALL Report AMP XI.M5, "BWR Feedwater Nozzle." The program is designed to ensure that aging degradation caused by cracking is adequately managed for the nozzle components, so that its intended function is maintained through the end of the period of extended operation.

The LRA states that its BWR Feedwater Nozzle program consists of augmented ISI in accordance with the requirements of the ASME Code, Section XI, Subsection IWB, Table IWB 2500-1, and the recommendations of General Electric (GE) NE-523-A71-0594-A, Revision 1. The program specifies periodic ultrasonic inspection of critical regions of the feedwater nozzles. In response to NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," design changes were made to the feedwater nozzles before initial reactor operation to mitigate or prevent thermally induced fatigue cracking. The current design does not include cladding on the nozzle inner surface and uses a triple thermal sleeve feedwater sparger design with two ring seals.

Staff Evaluation. During its audit, 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.M5.

In particular, the staff confirmed that the AMP addresses the detection and sizing of cracks by ISI in accordance with ASME Code, Section XI, Subsection IWB. The staff also confirmed that the inspection schedule is in accordance with Table 6-1 of the GE-NE-523-A71-0594-A, Revision 1, consistent with the recommendation of GALL Report AMP XI.M5. In addition, it was confirmed that the AMP requires that any repair or replacement activities be implemented in accordance with the guidelines of the ASME Code, Section XI, IWB-4000.

The staff also reviewed UFSAR Section 5.2.4.8 and confirmed that the feedwater nozzle has been modified and the current configuration is the triple-sleeve with two sister ring seals and an unclad nozzle. The staff noted that this design ensures the longest ISI intervals in accordance with NUREG-0619.

Based on its audit of the BWR Feedwater Nozzle program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M5.

Operating Experience. LRA Section B.2.1.5 summarizes operating experience related to the BWR Feedwater Nozzle program. The applicant stated that it started operation in 1986 with important design features recommended by NUREG-0619 incorporated into the plant design, including eliminating the cladding on the nozzle inner diameter and the use of low leakage triple thermal sleeve feedwater spargers. The applicant also stated that the feedwater nozzles have been inspected for cracking as part of the existing augmented ISI program, in accordance with the guidance in GE-NE- 523-A71-0594-A, Revision 1. Recordable indications were noted and a fracture mechanics analysis was performed in 2000 to validate the inspection interval based on the requirements of GE-NE-523-A71-0594-A, Revision 1.

The staff reviewed operating experience information in the application and during the audit to determine if the applicant reviewed the applicable aging effects and industry and plant-specific operating experience. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine if the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.
UFSAR Supplement. LRA Section A.2.1.5 provides the UFSAR supplement for the BWR Feedwater Nozzle program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR

Table 3.0-1. 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 BWR Feedwater Nozzle program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.6 BWR Stress Corrosion Cracking

Summary of Technical Information in the Application. LRA Section B.2.1.7 describes the existing BWR Stress Corrosion Cracking program as consistent with GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking." The BWR Stress Corrosion Cracking program is an existing condition monitoring and mitigation program that manages IGSCC in the piping and piping components made of stainless steel and nickel-based alloy in a reactor coolant environment as delineated in NUREG-0313, Revision 2, and NRC Generic Letter (GL) 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," dated January 25, 1988, and its Supplement 1, dated February 4, 1992. The program includes preventive measures to mitigate IGSCC, and inspection and flaw evaluation to monitor IGSCC and its effects.

Staff Evaluation. During its audit, 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.M7. For the "scope of program," and "detection of aging effect" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs as discussed below.

GALL Report AMP XI.M7 states that NUREG-0313, Revision 2, and GL 88-01 delineate the guidance for selection of resistant materials and processes that provide resistance to IGSCC, such as solution heat treatment and stress improvement processes. LRA Section B.2.1.7 states that this program implements the program delineated in NUREG-0313, Revision 2, and in GL 88-01 and its Supplement 1.

During the audit, the staff noted that the applicant's ISI program plan indicates that the following welds of LGS Units 1 and 2 are made of Alloy 182 with Alloy 182 weld butter: (1) recirculation outlet nozzle to safe-end welds for Loops A and B, (2) jet pump instrumentation nozzle to safe-end welds for Loops A and B, and (3) control rod drive (CRD) return nozzle-to-cap welds. Based on the guidance in GL 88-01, Attachment A, "Staff Position on Materials," the Alloy 182 welds of LGS Units 1 and 2 are not resistant to IGSCC. In addition, the applicant's ISI program plan indicates that ultrasonic examinations of Alloy 182 reactor pressure vessel (RPV) nozzle to safe-end welds (i.e., welds incorporating Alloy 182 welds and/or weld butters) at several BWR facilities have resulted in the detection of cracking, which appears to have initiated as IGSCC in the Alloy 182 weld butter.

During the audit of the onsite documentation, the staff also noted that the Alloy 182 welds of LGS Unit 1 are categorized to IGSCC Category C, consistent with the GL 88-01 guidance that Alloy 182 is not a resistant material. By contrast, the absence of Alloy 182 welds in the applicant's list for the IGSCC Category-B-through-G welds for LGS Unit 2 suggests that these welds are categorized to IGSCC Category A (resistant material), inconsistent with GL 88-01. The IGSCC categories of the welds in the BWR Stress Corrosion Cracking program are used to determine the inspection extent and frequency in accordance with GL 88-01 and BWRVIP-75-A. Therefore, the staff needed clarification for the following items about the Alloy 182 welds of LGS Unit 2: the proper IGSCC categories of these welds; the basis of the applicant's categorization of these welds; and consistency of the applicant's categorization with the guidance in GL 88-01 and the IGSCC categorization of the LGS Unit 1, Alloy 182 welds.

By letter dated November 18, 2011, the staff issued RAI B.2.1.7-1 requesting the applicant to describe the IGSCC categories of the LGS Unit 2 Alloy 182 welds listed in the applicant's ISI plan. The staff also requested the applicant to provide the basis for the applicant's IGSCC categorization of these Unit 2, Alloy 182 welds. The staff further requested that as part of the response, if any of these LGS Unit 2 Alloy 182 welds are categorized as IGSCC Category A, the applicant clarify why the weld is categorized as a resistant weld, inconsistent with the guidance in GL 88-01 and the weld categorization of the LGS Unit 1 Alloy 182 welds to IGSCC Category C.

In its response, provided by letter dated December 7, 2011, the applicant stated that the LGS Units 1 and 2 Alloy 182 welds were listed within the procedure for augmented ISI of Alloy 182 nozzle weldments. The applicant also indicated that during the AMP audit, the weld descriptions provided in this procedure were incorrect for five LGS Unit 2 welds and a CAP issue report has been initiated to correct this error on the weld description in this procedure. The applicant further clarified that the following five welds of LGS Unit 2 had an Alloy 82 inlay installed over the Alloy 182 weld/weld-butter before initial power operations, such that the Alloy 182 material has not been in contact with reactor coolant: Welds VRR-2RS-2A N1A, VRR-2RS-2B N1B, RPV-2IN N8A, RPV-2IN N8B, and RPV-2IN N9. In addition, the applicant clarified that these welds were correctly classified as IGSCC Category A in accordance with NUREG-0313, Revision 2. The applicant confirmed that IGSCC Category A, assigned to these welds, is appropriate since the Alloy 82 inlay material is considered resistant to IGSCC and was applied on these welds to prevent reactor coolant from contacting the Alloy 182 material. The applicant also stated that all LGS Units 1 and 2 Alloy 182 welds are categorized consistent with GL 88-01 and NUREG-0313, Revision 2, as described in its response. The staff finds the applicant's response acceptable because the applicant clarified and confirmed that the five welds made of Alloy 182 material have Alloy 82 inlay, which is classified as IGSCC Category A (resistant material), consistent with the guidance in GL 88-01, and the inlays were applied on these welds before the start of the initial power operation. The staff's concern described in RAI B.2.1.7-1 is resolved.

The "scope of program" program element of GALL Report AMP XI.M7 states that the program is applicable to all BWR piping and piping welds made of austenitic stainless steel and nickel alloy that are 4 inches or larger in nominal diameter containing reactor coolant at a temperature above 93° C (200 °F) during power operation, regardless of Code classification. In comparison, LRA Section B.2.1.7 states that the BWR Stress Corrosion Cracking program manages IGSCC in reactor coolant pressure boundary (RCPB) piping and piping components made of stainless steel and nickel-based alloy in a reactor coolant environment. In addition, LRA Table 3.2.1, item 3.2.1-54 indicates that the GALL Report recommends the BWR Stress Corrosion Cracking program to manage cracking caused by SCC and IGSCC of stainless steel piping, piping components, and piping elements exposed to treated water greater than 60° C (140 °F). The staff also noted that LRA Table 3.2.1, item 3.2.1-54 is for the ESF. However, LRA Table 3.1.2-1 and related information in the LRA indicate that the applicant credited LRA Table 3.2.1, item 3.2.1-54 to manage the aging effect of RCPB components only.

During the audit, the staff further noted that the applicant's weld selection table for ISI indicates that the applicant's program includes two ASME Code Class 2 welds associated with valves in the reactor water cleanup (RWCU) system of LGS Unit 1. One of the welds is IGSCC Category B and the other weld is IGSCC Category C.

In comparison, the LRA does not clearly address whether the scope of the applicant's program includes piping and piping welds regardless of ASME Code classification, consistent with the GALL Report recommendations. The staff noted that the LRA includes the RCPB in the program scope; however, the LRA does not clearly address whether the scope of the program includes non-Class-1 piping and its associated welds. In addition, the staff noted that RWCU system piping and piping welds outboard of the second containment isolation valves are included in the scope of GALL Report AMP XI.M25, "BWR Reactor Water Cleanup System," while RWCU system piping and piping welds inboard of the second containment isolation valves are included in the BWR Stress Corrosion program. Therefore, the staff needed to further clarify if the LGS Unit 1 ASME Code Class 2 welds, categorized as IGSCC Category B and C, are located inboard of the second containment isolation valves.

By letter dated January 17, 2012, the staff issued RAI B.2.1.7-2 requesting the applicant to describe if the scope of applicant's program includes BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of ASME Code classification, consistent with the GALL Report recommendations. The staff also requested that if the scope of the applicant's program does not include non-Class-1 piping and piping welds, the applicant justify why non-Class-1 piping and piping welds can be excluded from the program scope. In addition, the staff requested that the applicant revise LRA Section A.2.1.7 (UFSAR supplement) to clarify that the scope of the program includes the relevant piping and piping welds regardless of Code classification. The staff further requested that the applicant clarify if the ASME Code Class 2 welds associated with the valves in the LGS Unit 1 RWCU system are located inboard of the second containment isolation valves (i.e., "inboard" valves). The staff requested that if these ASME Code Class 2 welds are associated with inboard valves, the applicant clarify why its statement that the program manages the aging effect of the RCPB components is consistent with the inclusion of these ASME Code Class 2 welds in the program.

In its response, provided by letter dated February 15, 2012, the applicant indicated that the two ASME Code Class 2 welds in the RWCU system are located outboard of the second containment isolation valve, for which no augmented inspection is required. The applicant further indicated that since these two welds had been incorrectly identified as the welds that should be included in the inspection in accordance with GL 88-01, a CAP issue report was issued in August 2010, to correctly identify that these welds are not within the augmented inspections specified in GL 88-01. The staff found this portion of the applicant's response adequate because it clarified the outboard locations of the welds in the RWCU system, and the GALL Report recommends GALL Report AMP XI.M25, "BWR Reactor Water Cleanup System," to manage the aging effect of these outboard welds rather than the BWR Stress Corrosion Cracking program.

In its response regarding program scope, the applicant confirmed that the BWR Stress Corrosion Cracking program includes BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of ASME Code classification. The applicant also stated that the determination of program scope included screening of all BWR piping and piping welds made of austenitic stainless steel that are 4 inches or greater in nominal diameter containing reactor coolant at a temperature greater than 93° C (200 °F) during power operation, regardless of Code classification. The applicant further stated that this screening identified only ASME Code Class 1 piping as within the scope of the BWR Stress Corrosion Cracking program. The staff found that this portion of the applicant's response is acceptable because the applicant confirmed that the scope of the program includes all relevant piping and piping welds regardless of ASME Code classification, consistent with the GALL Report, and the applicant's screening of the welds in accordance with the GALL Report identified only RCPB welds as the welds to be inspected in the program.

However, the staff noted that the revised UFSAR supplement in the applicant's response states that the BWR Stress Corrosion Cracking program is an existing augmented ISI program that manages IGSCC in reactor coolant pressure boundary piping and piping components made of stainless steel and nickel-based alloy, regardless of Code classification, as delineated in NUREG-0313, Revision 2, and GL 88-01 and its Supplement 1. In its review, the staff finds that the applicant's revision to the UFSAR supplement, which includes the reference to "reactor coolant pressure boundary piping," is in conflict with the applicant's response indicating that the program includes all relevant piping regardless of ASME Code classification. Therefore, this part specifically related to the UFSAR supplement is further evaluated in the evaluation section for the UFSAR supplement as described below. Based on this review, the staff's concern described in RAI B.2.1.7-2 is resolved, except for aspects related to the applicant's revision to the UFSAR supplement.

The "detection of aging effect" program element of GALL Report AMP XI.M7 states that the extent, method, and schedule of the inspection and test techniques delineated in GL 88-01 or BWRVIP-75-A are designed to maintain structural integrity and ensure that aging effects are discovered and repaired before the loss of intended function of the component. The GALL Report also states that modifications to the extent and schedule of inspection in GL 88-01 are allowed in accordance with the inspection guidance in approved BWRVIP-75-A. The LRA further states that welds classified as Category A have been subsumed into the RI-ISI program in accordance with staff-approved EPRI Topical Report TR-112657, Revision B-A, Final Report, "Revised Risk-Informed Inservice Inspection Evaluation Procedure," issued December 1999.

Although the applicant indicated that the program uses a staff-approved methodology described in EPRI TR-112657, Revision B-A, to subsume IGSCC Category A welds in RI-ISI, the staff noted that the relief request was approved for the applicant's third 10-year inservice inspection interval, which is scheduled to end on January 31, 2017. The staff noted that the applicant would need to get NRC approval for using this risk-informed method, for the period of extended operation, as an alternative to the ASME Code Section XI inservice inspection requirements for piping and the inspection requirements of GL 88-01. Therefore, the staff needed to further clarify what extent, method, and schedule the applicant would use to inspect the piping and piping components in the scope of the BWR Stress Corrosion Cracking program in the case the applicant could not continue to get NRC approval for using the risk-informed method described in EPRI TR-112657, Revision B-A. The staff also found that the UFSAR supplement for this program should be further evaluated in terms of its consistency with the program on the use of the risk-informed method.

By letter dated January 17, 2012, the staff issued RAI B.2.1.7-3 requesting the applicant to describe the extent, method, and schedule that the applicant would use to inspect the piping and piping components in the scope of the BWR Stress Corrosion Cracking program in the case the applicant could not continue to get NRC approval for using the risk-informed method described in EPRI TR-112657, Revision B-A. The staff also requested that the applicant revise LRA Section A.2.1.7 (UFSAR supplement), consistent with the applicant's response on the need to remove the applicant's reference to the risk-informed ISI from the UFSAR supplement.

In its response, provided by letter dated February 15, 2012, the applicant clarified that in the event that NRC approval is not provided to use the risk-informed methodology described in EPRI TR-112657, Revision B-A, for scheduling inspections for IGSCC Category A welds, the extent and schedule of the inspection and test techniques would be in accordance with the inspection guidance in approved BWRVIP-75-A. The applicant also stated that the inspection method is not affected by use of the risk-informed methodology and is in accordance with GL 88-01 and NUREG-0313, Revision 2. In addition, the applicant provided the revision to the UFSAR supplement, consistent with the applicant's response. The staff finds the applicant's response acceptable because the applicant confirmed that in the case the applicant cannot get NRC approval for using the risk-informed inspection methodology, the extent, method, and schedule of the inspections would be consistent with staff-approved guidance, and the applicant's revisions to the UFSAR supplement, which removed a reference to the risk-informed methodology, is consistent with the acceptable response. The staff's concern described in RAI B.2.1.7-3 is resolved.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.7-1, B.2.1.7-2, and B.2.1.7-3 of the BWR Stress Corrosion Cracking program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M7.

<u>Operating Experience</u>. LRA Section B.2.1.7 summarizes operating experience related to the BWR Stress Corrosion Cracking program. The LRA states that during the LGS Unit 1 1989 refueling outage, a volumetric UT identified a cracking indication in a reactor recirculation nozzle to safe-end weld that resulted in this weld being classified as IGSCC Category F in accordance with GL 88-01 and NUREG-0313, Revision 2 guidelines. The applicant also indicated that mechanical stress improvement process (MSIP) was performed on this weld in 1992 and the weld was re-examined during each of the following four refueling outages in accordance with GL 88-01 guidance. The applicant further indicated that since none of these re-examinations indicated crack growth, the weld was upgraded to Category E and examination of this weld has continued during every other refueling outage in accordance with BWRVIP-75-A guidance.

The applicant stated that this example illustrates how implementation of industry operating experience from GL 88-01 and volumetric ultrasonic testing was applied to identify a cracking indication in a susceptible RCPB weld. Furthermore, this example demonstrates effective use of industry recommendations to apply MSIP on a weld with a crack indication as a mitigating action to reduce the stresses in the weld and probability for continued SCC. The applicant also stated that this example demonstrates how the guidelines in GL 88-01, NUREG-0313, and BWRVIP-75-A are applied effectively to classify a weld with cracking indication and to appropriately schedule and perform examinations to confirm that the condition of the weld is acceptable for continued service.

LRA Section B.2.1.7 states that NUREG-0313, Revision 2, and GL 88-01 provide recommendations to perform MSIP on welds that were susceptible to SCC to reduce the tensile stresses and the susceptibility to SCC. The applicant also indicated that MSIP was performed on LGS Unit 1 in 1992 and 1994 on 23 welds within the scope of the GL 88-01 that had no evidence of prior cracking and on one weld that had indications of prior cracking. The applicant further indicated that MSIP was performed on LGS Unit 2 before reactor operations on 18 welds and the augmented ISIs to examine SCC has been in place since 1988, in accordance with GL 88-01 and BWRVIP-75-A. In addition, the applicant indicated that the inspections have not identified any indications of cracking in susceptible welds following the application of MSIP to those welds determined to be most susceptible.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicant reviewed applicable aging effects and industry and plant-specific operating experience. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.7, as amended by letter dated February 15, 2012, provides the UFSAR supplement for the BWR Stress Corrosion Cracking program. The staff reviewed this UFSAR supplement and needed further clarification on the scope of the program described in the UFSAR supplement. The staff noted that the licensing basis for this program for the period of extended operation may not be adequate if the applicant does not provide sufficient information and clarification on its UFSAR supplement.

As described above in the staff safety evaluation regarding RAI B.2.1.7-3, the applicant, in its letter dated February 15, 2012, removed reference to the risk-informed inspection methodology from the UFSAR supplement. The staff finds this revision acceptable because the use of the risk-informed methodology is granted only for a specific inspection interval and needs additional reviews and NRC approval for continued use.

As addressed above in the staff's safety evaluation regarding RAI B.2.1.7-2, the staff requested the applicant to describe whether the scope of the applicant's program includes BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of ASME Code classification, consistent with the GALL Report. In the same RAI, the staff also requested that the applicant revise LRA Section A.2.1.7 (UFSAR supplement) appropriately to clarify that the scope of the program includes the relevant piping and piping welds regardless of ASME Code classification.

In its letter dated February 15, 2012, the applicant clarified that the BWR Stress Corrosion Cracking program includes BWR piping and piping welds made of austenitic stainless steel and nickel alloy regardless of ASME Code classification. The applicant also stated that determination of program scope included screening of all BWR piping and piping welds made of austenitic stainless steel that are 4 inches or greater in nominal diameter containing reactor coolant at a temperature greater than 93° C (200 °F) during power operation, regardless of Code classification. However, in its review, the staff found that the applicant's revision to the UFSAR supplement, which includes reference to "reactor coolant pressure boundary piping," conflicts with the applicant's response, indicating that the program includes all relevant piping regardless of Code classification. By letter dated April 5, 2012, the staff issued RAI B.2.1.7-2.1 requesting the applicant to justify why its revised UFSAR supplement includes "reactor coolant pressure boundary piping," which is inconsistent with other text in the RAI response indicating that the program includes relevant piping and piping welds regardless of Code classification.

In its response, provided by letter dated April 13, 2012, the applicant revised the UFSAR supplement (LRA Section A.2.1.7) to include "relevant piping and piping welds" without a reference to "reactor coolant pressure boundary piping and piping components," consistent with the program description provided in its response to RAI B.2.1.7-2. The staff reviewed the applicant's revision to the UFSAR supplement and found the response acceptable because the revised UFSAR is consistent with the program scope of GALL Report AMP XI.M7.

The staff finds that the information in the UFSAR supplement, as amended by letters dated February 15, 2012, and April 13, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the BWR Stress Corrosion Cracking program, the staff concludes that the program elements, for which the applicant claimed consistency with the GALL Report, are consistent with the corresponding program elements of GALL Report AMP XI.M7. 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).

3.0.3.1.7 BWR Penetrations

Summary of Technical Information in the Application. LRA Section B.2.1.8 describes the existing BWR Penetrations program as consistent with GALL Report AMP XI.M8, "BWR Penetrations." This program is a condition monitoring and mitigation program that manages the effects of cracking of the reactor vessel instrumentation penetrations, and CRD housing and in-core-monitoring housing penetrations exposed to reactor coolant through water chemistry and ISIs. It also incorporates the inspection and evaluation recommendations of BWRVIP-49-A, "Instrument Penetration Inspection and Flaw Evaluation Guidelines," BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines," and the water chemistry recommendations as described in the Water Chemistry program. Each refueling outage, a visual inspection (VT-2) is performed on these components during the system leakage test in accordance with the controlling edition of ASME Code, Section XI. BWRVIP-27-A states that it does not apply to plants such as LGS, in which standby liquid control (SLC) injects by CS system piping.

Staff Evaluation. During its audit, 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.M8. For the "parameters monitored or inspected" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs as discussed below.
The "parameters monitored or inspected" program element of GALL Report AMP XI.M8 states that it manages the effects of cracking caused by SCC and IGSCC on the intended function of the BWR instrumentation nozzles, CRD housing and in-core monitoring housing (ICMH)

penetrations, and BWR SLC nozzles/core ΔP nozzles. It also states that the program accomplishes this aging management by inspecting for cracks in accordance with the staff approved BWRVIP guidelines (e.g., BWRVIP-47-A) and the requirements of ASME Code, Section XI, Table IWB 2500-1.

Section 3.2.5, "Other Inspections," of BWRVIP-47-A indicates that removing or dismantling internal components for the purpose of performing inspections is not warranted to ensure safe operation; however, on occasion, utilities may have access to the lower plenum because of maintenance activities that are not part of normal refueling outage activities. It also states that in such cases utilities will perform a visual inspection to the extent practical and the results of the inspection will be reported to the BWRVIP, which will report these results to the NRC.

The "parameters monitored or inspected" program element of the applicant's program basis document states that the program monitors the effects of cracking caused by SCC and IGSCC by performing inspections of the instrumentation nozzles, CRD housing, and ICMH penetrations as part of the ISI program. However, the program basis document states that currently, BWRVIP-47-A does not require additional inspections of the CRD housing and ICMH penetrations. Therefore, it is not clear to the staff if the applicant's basis document for the BWR Penetrations program is consistent with Section 3.2.5 of BWRVIP-47-A in terms of the inclusion of the additional inspections.

By letter dated November 18, 2011, the staff issued RAI B.2.1.8-1 requesting the applicant to justify why its program indicates that BWRVIP-47-A does not require additional inspections for the CRD housing and ICMH penetrations. In addition, the RAI requested the applicant describe any results of the inspections performed in accordance with Section 3.2.5 of BWRVIP-47-A.

In its response, provided by letter dated December 7, 2011, the applicant confirmed that it performs the inspections described in Section 3.2.5 of BWRVIP-47-A as part of its inspections for reactor vessel internals (RVIs) and that the inspections are included in the BWR Penetrations program. The applicant also indicated that the program basis document was revised to delete the sentence indicating that currently the BWRVIP-47-A does not require additional inspections of the CRD housing and ICMH penetrations. In addition, the applicant discussed the following inspection results for the lower plenum components, which were performed in accordance with BWRVIP-47-A.

During the LGS Unit 2, refueling outage in 2007, nine CRD housing-to-stub-tube welds were examined when they were accessible during maintenance of jet pumps and no recordable indications were identified as described in a letter from C. Mudrick to the NRC, "LGS Unit 2 Summary Report for Inservice Inspections (2R09)," dated July 3, 2007. In addition, during the LGS Unit 1, refueling outage in 2010, eight CRD housing-to-stub-tube welds, eight CRD stub-tube-to-reactor-pressurevessel (RPV) welds, and four ICMH-to-RPV penetration welds were examined when they were made accessible during cleaning of the RPV bottom head drain. No recordable indications were identified as described in letter from W. Maguire to the NRC, "LGS Unit 1 Summary Report for Inservice Inspections (1R13)," dated July 9, 2010. The applicant stated that these results confirm that the inspection results are consistent with the conclusion that the aging effects will be adequately managed.

The staff finds the applicant's response to RAI B.2.1.8-1 acceptable because the results of the applicant's inspections performed in accordance with BWRVIP-47-A did not identify any recordable indication for the lower core plenum penetrations and the applicant's program basis document has been revised to delete the incorrect statement about the additional inspections of BWRVIP-47-A. The staff's concern described in RAI B.2.1.8-1 is resolved.

In its review, the staff noted that Section 3.2, "BWRVIP Inspection Guidelines," of BWRVIP-47-A indicates that if there is bottom head access as a result of normal refueling outage activities, ASME Code, Section XI, requires visual inspection of accessible areas in the region to be performed. In comparison, the applicant's onsite procedure indicates that on April 30, 2008, the staff approved ISI program relief request such that the use of the BWRVIP Inspection and Evaluation Guidelines was authorized in place of ASME Code-required inspections and flaw evaluations for ASME Code, Section XI, B-N-1 and B-N-2 category components. The applicant's procedure further indicated that this relief request is applied to "CRD stub tube to vessel attachments (inaccessible)" and "CRD housing to stub tube welds (inaccessible)."

However, Attachment 1 to the staff's safety evaluation, dated April 30, 2008, of the relief request does not list CRD stub tubes or associated welds as components for which the relief request was approved. Therefore, the staff needed to clarify why the relief request is applied to the CRD stub tubes and associated welds and when the CRD stub-tube-to-vessel attachment welds and CRD housing-to-stub-tube welds are accessible for inspections.

By letter dated November 18, 2011, the staff issued RAI B.2.1.8-2 requesting the applicant to clarify the discrepancy between its onsite procedure and the approved relief request and when the welds described above are accessible for inspections.

In its response, provided by letter dated December 7, 2011, the applicant stated that the CRD stub-tube-to-vessel welds and CRD housing-to-stub-tube welds are located in the lower plenum region of the RPV and are only accessible for inspections during certain maintenance activities that are not part of normal refueling activities. Access to the lower plenum region of the RPV can be through disassembly of jet pumps or through the core plate following removal of control rod guide tubes. Examples of the types of maintenance activities that result in access to these components to perform inspections include maintenance to the jet pumps and cleaning of the RPV bottom head drain. The applicant indicated that its response to RAI B.2.1.8-1 includes recent examples of inspections performed on the CRD stub-tube-to-vessel welds, CRD housing-to-stub-tube welds, and ICMH-to-vessel welds when these components were made accessible by these maintenance activities. As described in the response to RAI B.2.1.8-1, the applicant confirmed that the results of the applicant's inspections performed in accordance with BWRVIP-47-A identified no recordable indications for these lower plenum penetration components.

In its response, the applicant also indicated that the implementing procedure was found to be incorrect in stating that the relief request applies to examination of the CRD stub-tube-to-vessel welds and CRD housing-to-stub-tube welds. In addition, the applicant stated that its procedure has been revised to delete the reference to this relief request relative to these welds.

The staff finds the applicant's response to RAI B.2.1.8-2 acceptable because the applicant confirmed that the implementing procedure was revised to clarify that its relief request is not applied to these lower plenum penetration welds and the lower plenum penetration components are only accessible for inspections during certain maintenance activities that are not part of normal refueling activities.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.8-1 and B.2.1.8-2 of the BWR Penetrations program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M8.

<u>Review of License Renewal Applicant Action Items</u>: In the staff's safety evaluation, dated September 1, 1999, for BWRVIP-49, "BWR Vessel and Internals Project, Instrument Penetration Inspection and Flaw Evaluation Guidelines," three license renewal applicant action items (AAIs) were issued in the report. In addition, the staff's safety evaluation, dated December 7, 2000, issued four licensee renewal AAIs for BWRVIP-47, "BWR Vessel and Internals Project, BWR Lower Plenum Inspection and Flaw Evaluation Guidelines (BWRVIP-47)." Three of the four AAIs for BWRVIP-47 are essentially identical to the three action items for BWRVIP-49 as summarized below. The fourth AAI specific to BWRVIP-47 follows these three AAI:

> AAI #1: The license renewal applicant is to verify that its plant is bounded by the BWRVIP report. Further, the renewal applicant is to commit to programs described as necessary in the BWRVIP report to manage the effects of aging on the functionality of the reactor vessel components addressed in the BWRVIP report during the period of extended operation. License renewal applicants will be responsible for describing any such commitments and identifying how such commitments will be controlled. Any deviations from the AMPs within the BWRVIP report described as necessary to manage the effects of aging during the period of extended operation and to maintain the functionality of the reactor vessel components or other information presented in the report, such as materials of construction, will have to be identified by the renewal applicant and evaluated on a plant-specific basis in accordance with 10 CFR 54.21(a)(3) and (c)(1).
>
> AAI #2: 10 CFR 54.21(d) requires that a UFSAR supplement for the facility contain a summary description of the programs and activities for managing the effects of aging and the evaluation of TLAA (time-limited aging analysis) for the period of extended operation. Those applicants for license renewal referencing the BWRVIP report for the reactor vessel components shall ensure that the programs and activities specified as necessary in the BWRVIP document are summarily described in the UFSAR supplement.
>
> AAI #3: 10 CFR 54.22 requires that each license renewal application include any Technical Specification changes (and the justification for the changes) or additions necessary to manage the effects of aging during the period of extended operation as part of the license renewal application. Those license renewal applicants referencing the BWRVIP report for the reactor vessel components shall ensure that the inspection strategy described in the BWRVIP report does not conflict or result in any changes to their Technical Specifications. If technical specification changes do result, then the applicant should ensure that those changes are included in its license renewal application.

In addition to these three action items for BWRVIP-49 and BWRVIP-47, the staff safety evaluation for the BWRVIP-47 report issues the fourth license renewal action item as follows:

AAI #4: Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for license renewal should identify and evaluate the projected cumulative usage factor (CUF) as a potential TLAA issue. This issue is discussed in more detail in Section 3.5 of BWRVIP-47.

As discussed in SER Section 4.1.2.1.2, the staff issued RAI BWRVIP-1, by letter dated January 17, 2012, requesting the applicant to submit the necessary information for each AAI in the BWRVIP reports that are applicable to the LGS CLB. By letter dated February 15, 2012, the applicant responded to RAI BWRVIP-1, which addresses the necessary information and revisions to the LRA for license renewal AAIs in all applicable BWRVIP reports that are credited for aging management. In its response, the applicant revised LRA Appendix C, "Response to BWRVIP License Renewal Applicant Action Items."

The staff reviewed the applicant's response to AAI #1, which states that the BWRVIP reports applicable to the applicant have been reviewed and the applicant's AMP has been confirmed to be bounded by the reports. The applicant also stated in its response that it committed to programs described as necessary in the BWRVIP reports to manage the effects of aging during the period of extended operations.

The staff confirmed that LRA Appendix A describes the applicant's UFSAR supplement and adequately identifies staff-approved BWRVIP-47-A and BWRVIP-49-A as the industry guidelines to be incorporated in the BWR Penetration program. The applicant confirmed that BWRVIP-47-A and BWRVIP-49-A bound the BWR Penetrations program. In addition, the applicant stated that if, upon review of a BWRVIP approved guideline, it determines that known deviations to full compliance are warranted, the NRC will be notified of the deviation within 45 days of the receipt of NRC final approval of the guideline, and commitments are administratively controlled in accordance with the requirements of Appendix B to 10 CFR Part 50. The staff finds that the applicant has adequately addressed Action Item #1 because it confirmed that its program is bounded by BWRVIP-47-A and BWRVIP-49-A and the program does not have any other commitment than the ongoing implementation of the existing BWR Penetrations program, which is administratively controlled in accordance with Appendix B to 10 CFR Part 50.

The staff reviewed the applicant's response to AAI #2, which states the UFSAR supplement is included in LRA Appendix A and contains a summary description of the programs and activities specified as necessary for managing the effects of aging per the BWRVIP reports. The staff finds that the UFSAR supplement for the BWR Penetrations program is sufficient to summarize the program activities consistent with the SRP-LR and the GALL Report, including the inspections and flaw evaluation addressed in BWRVIP-47-A and BWRVIP-49-A. Therefore, the applicant has adequately addressed AAI #2 for the BWRVIP reports by providing a sufficient UFSAR summary description for the BWR Penetrations program.

The staff reviewed the applicant's response to AAI #3, which states that there are no technical specification changes identified to meet the recommendations of the BWRVIP reports during the period of extended operation. The staff confirmed that LRA Appendices C and D indicate that no technical specification changes or additions were identified as necessary to manage the effects of aging during the period of extended operation. The staff finds the applicant's response to AAI #3 acceptable because the applicant confirmed that no change to the technical specifications is needed to manage the aging effects in accordance with the BWRVIP reports.

The staff reviewed the applicant's response to AAI #4 specific to BWRVIP-47, which states that fatigue usage is considered a time-limited aging analysis (TLAA) for RVIs, including lower plenum components. The staff noted that Section 3.5 of the staff safety evaluation for BWRVIP-47 indicates that some plants may have lower plenum pressure boundary component fatigue CUF greater than the ASME Code design limit of 1.0 for the license renewal term and a plant-specific description of how this issue will be addressed is needed for these plants. The staff noted that the applicant's fatigue TLAA of the lower plenum penetrations (i.e., CRD housing and in-core monitor penetrations) are addressed in LRA Section 4.3.3 and LRA Table 4.3.3-1. In addition, the identification of the fatigue TLAA of these components is addressed in the applicant's AMR results described in LRA Table 3.1.2-2 for RPV components. The staff finds the applicant's response acceptable because the LRA identifies and includes the fatigue TLAA of the lower plenum penetration components, consistent with BWRVIP-47-A.

Operating Experience. LRA Section B.2.1.8 summarizes operating experience related to the BWR Penetrations program. The applicant stated that, as required by the ASME Code, Section XI, an RCPB system leakage test is performed on the reactor vessel instrument penetrations and CRD housing and ICMH penetrations for each refueling outage in accordance with the ISI program. The applicant also stated that a review of the inspection results from the last two refueling outages for both Units (2007, 2008, 2009, and 2010) indicates that there have been no leaks identified for these components. In addition, as part of its response to RAI B.2.1.8-1, the applicant confirmed that the results of the visual inspections performed in accordance with BWRVIP-47-A, Section 3.2.5, identified no recordable indications for the lower core plenum penetration components.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicant reviewed the aging effects and industry and plant-specific operating experience. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation. Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.8 provides the UFSAR supplement for the BWR Penetrations program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 BWR Penetrations program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.8 Flow-Accelerated Corrosion

Summary of Technical Information in the Application. LRA Section B.2.1.10 describes the existing Flow-Accelerated Corrosion program as consistent with GALL Report AMP XI.M17, "Flow-Accelerated Corrosion." The program predicts, detects, and monitors wall thinning caused by flow-accelerated corrosion of piping components and heat exchangers in steam and treated water environments. The program is based on EPRI guidelines in NSAC-202L, Revision 3, "Recommendations for an Effective Flow Accelerated Corrosion Program," and uses a predictive computer code, CHECWORKS, to analytically determine critical locations to inspect. Inspections are performed using ultrasonic, visual, or other approved testing techniques capable of detecting wall thinning. For each inspected component, the program uses a PC-based computer program called FAC (flow-accelerated corrosion) Manager, in conjunction with CHECWORKS, to calculate component wear rate, projected thickness, and remaining life. For components with a remaining life of less than one operating cycle, corrective actions, such as repair, replacement, or reevaluation, are implemented.

Staff Evaluation. During the audit, 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.M17. Based on its audit of the Flow-Accelerated Corrosion program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M17.

Operating Experience. LRA Section B.2.1.10 summarizes operating experience related to the Flow-Accelerated Corrosion program. The LRA provided a summary of the recent inspections, which included 102 inspections for LGS Unit 1 in 2010, and 83 inspections for LGS Unit 2 in 2009. The LRA also described additional inspections performed during outages. These inspections led to replacement of selected large- and small-bore piping with material resistant to flow-accelerated corrosion containing 1.25 percent chromium. In addition, the LRA described the evaluation of industry operating experience related to feedwater heater shell leakage in establishing feedwater heater shell inspection plans. The LRA stated that these examples provided objective evidence that the Flow-Accelerated Corrosion program has been effective in ensuring that the intended functions are being maintained consistent with the CLB.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicant reviewed the applicable aging effects and industry and plant-specific operating experience. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.10 provides the UFSAR supplement for the Flow-Accelerated Corrosion program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 Flow-Accelerated Corrosion program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M17. 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).

3.0.3.1.9 Compressed Air Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.15 describes the existing Compressed Air Monitoring program as consistent with GALL Report AMP XI.M24, "Compressed Air Monitoring." The program is based on the applicant's response for LGS to GL 88-14, "Instrument Air Supply Problems." The LRA states that the program manages loss of material in piping, piping components, piping elements, and valve bodies in air and gas environments. The LRA also states that the program includes periodic testing and inspection of the compressed air, primary containment instrument gas (PCIG), and traversing in-core probe systems. Program activities include air quality monitoring and trending, preventive maintenance, and condition monitoring measures to manage the effects of aging.

Staff Evaluation. During its audit, 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.M24.

For the "monitoring and trending" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "monitoring and trending" program element in GALL Report AMP XI.M24 recommends that daily readings of system dew point be recorded and trended. However, during its audit, the staff found that the applicant's program basis document for the Compressed Air Monitoring program states that the instrument air system dew point is continuously monitored and alarmed, inspected weekly, and recorded quarterly. The basis document also states that the primary containment instrument gas system's dryer desiccant outlet moisture indicator is confirmed weekly. Additionally, the program basis document states that trending is accomplished by satisfactory completion of the surveillances and quarterly recorded values and issue reports are initiated for alarms, test, or inspection results that do not satisfy the established criteria. By letter dated January 17, 2010, the staff issued RAI B.2.1.15-1 requesting the applicant to: explain why weekly inspections and quarterly recording of the instrument air system dew point are sufficient to detect potentially unacceptable levels of moisture; explain why it was using a desiccant outlet moisture indicator for the PCIG system instead of monitoring dew point; explain why verifying the desiccant outlet moisture indicator on a weekly basis is sufficient to detect potentially unacceptable levels of moisture; and state whether prior data points are compared to current data points during trending, and, if not, state why the trending of data points will be sufficient to detect changes in air quality before degrading air quality affects the ability of the instrument air systems to meet their intended function(s).

In its response, provided by letter dated February 15, 2012, with regard to daily recordings and trending of the dew point, the applicant stated that the instrument air system is continuously monitored and alarmed in the main control room to ensure moisture content is within specifications. To supplement the continuous monitoring activity, operators inspect and verify that the instrument air dryer outlet dew point is within its required range on a weekly basis. The applicant also stated that in response to GL 88-14, it committed to verify instrument air quality at safety-related components each refueling outage, and that this verification validates the continuous and weekly inspection activities. The applicant concluded that the continuous monitoring and alarm system along with weekly operator inspections of the instrument air system dew point are sufficient to detect potentially unacceptable levels of moisture within components. The applicant further stated that system managers review system health parameters quarterly to monitor system performance and ensure early detection of equipment problems.

With regard to the desiccant outlet moisture indicator for the PCIG system, the applicant stated the system uses the desiccant dryer outlet moisture indicator to monitor moisture and operators inspect the moisture indicator weekly to verify that moisture content is in an acceptable range. The applicant justified the use of a moisture indicator in place of direct dew point monitoring as consistent with the American National Standards Institute (ANSI) ISA-S7.0.01 standard.

With regard to whether prior data points are compared to current data points during trending, the applicant stated that it will enhance its program to meet the guidance of ASME O/M-S/G-1998, Part 17, which is consistent with the GALL Report recommendations. In addition, the applicant revised LRA Sections A.2.1.15 and B.2.1.15, as well as Commitment No. 15, to add an enhancement to the Compressed Air Monitoring program to perform trending.

The staff finds the applicant's response acceptable because the applicant will continuously monitor the dew point (instrument air) and the desiccant dryer outlet (PCIG), which will alert the applicant to any potential moisture within the systems. Additionally, the applicant will perform weekly inspection activities to verify that moisture content is within the acceptable range. Lastly, the applicant has included in its UFSAR supplement a commitment (Commitment No. 15) to enhance the Compressed Air Monitoring program to perform periodic analysis and trending of air quality monitoring results. Trending of the data will reveal any adverse trends and the need for system attention. The staff's concern described in RAI B.2.1.15-1 is resolved.

Enhancement. LRA Section B.2.1.15, as amended by letter dated February 15, 2012, states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that it will perform periodic analysis and trending of air quality monitoring results. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M24 and finds it acceptable because when it is implemented, the applicant's program will be consistent with the GALL Report.

Based on its audit, and review of the applicant's response to RAI B.2.1.15-1, of the Compressed Air Monitoring program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M24. In addition, the staff reviewed the enhancement associated with the "monitoring and trending," program element and finds that when implemented, the AMP will be adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.15 summarizes operating experience related to the Compressed Air Monitoring program. A summary of the four examples provided in the LRA is given below.

(1) In February 2002, a low dew point alarm was received in the main control room. An issue report was generated following receipt of the alarm. As part of troubleshooting and investigation, a replacement moisture monitoring instrument was obtained and installed. During the shift following installation, multiple low dew point alarms were received and the dryer component continued to be monitored closely. During the subsequent monitoring, the trend of dew point continued to improve and the alarms cleared. Dew point was confirmed to be maintaining a value in the acceptable range.

(2) In February 2007, carbon steel drain lines from the backup service air compressor were identified to be in a rusted condition near their termination point. Evaluation determined that continued degradation of the drain lines was not acceptable, and the lines were scheduled for replacement with stainless steel lines. Replacement of the lines was subsequently completed.

(3) In November 2005, the 2A instrument air compressor was noted to be making atypical noise. While the unit was operating within parameters, the intercooler pressure appeared to be fluctuating. The observer generated an issue report for followup investigation. The investigation determined that the recently performed surveillance capacity test was completed satisfactorily for the unit, but also confirmed that the unloader valve was chattering. The unit continued to function within parameters, but it was placed on an increased surveillance frequency as a precaution and the condition was corrected during the following annual minor overhaul.

(4) In June 2006, nuclear oversight performed an assessment of the scheduled maintenance activities package for the 1B instrument air compressor overhaul and aftercooler cleaning and inspection. During the performance of the maintenance activities, the nuclear oversight review noted potential for improvement in safety and protection for both personnel and equipment. Actions were created to incorporate the improvements into future maintenance packages.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicant reviewed applicable aging effects and industry and plant-specific operating experience. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.15 provides the UFSAR supplement for the Compressed Air Monitoring program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1 and noted that it does not credit the response to GL 88-14 and standards used as guidance for testing and monitoring air quality and moisture. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information in its UFSAR supplement. By letter dated January 17, 2012, the staff issued RAI B.2.1.15-2 requesting the applicant to explain why it is not necessary to reference its response to GL 88-14 and standards, such as ISA-S7.0.1, which it uses for air quality testing in the UFSAR supplement, or to revise LRA Section A.2.1.15 to include key aspects of the program that provide guidance for testing and monitoring air quality and moisture.

In its response, provided by letter dated February 15, 2012, the applicant stated that it revised LRA Section A.2.1.15 to reference the GL 88-14 response per the guidance in the SRP, Table 3.0-1.

The staff finds the applicant's response acceptable because it revised its description of the program in the UFSAR supplement to reference its response to GL 88-14. Therefore, the UFSAR supplement for the Compressed Air Monitoring program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.2.1.15-2 is resolved. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 15) to enhance the Compressed Air Monitoring program before the period of extended operation. The staff finds that the information in the UFSAR supplement, as amended by letter dated February 15, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the Compressed Air Monitoring program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR supplement contains Commitment No. 15 to implement the enhancement before the period of extended operation. 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).

3.0.3.1.10 BWR Reactor Water Cleanup System

Summary of Technical Information in the Application. LRA Section B.2.1.16 describes the existing BWR Reactor Water Cleanup System program as consistent with GALL Report AMP XI.M25, "BWR Reactor Water Cleanup System." The LRA states that the AMP is a condition monitoring and mitigation program, consisting of augmented ISI for SCC or IGSCC on stainless steel RWCU system piping welds outboard of the second primary containment isolation valves. The program is implemented in conjunction with the Water Chemistry program to minimize the potential of cracking because of SCC or IGSCC in a treated water environment. The LRA also states that the program includes measures in NUREG-0313, Revision 2, "Technical Report on Material Selection and Processing Guidelines for BWR Coolant Pressure Boundary Piping," dated January 1988, and GL 88-01, "NRC Position on IGSCC in BWR Austenitic Stainless Steel Piping," dated January 25 1988, and its Supplement 1 dated February 4, 1992. The LRA further states that the staff approved the elimination of examinations of the outboard portion of the RWCU system for both units; however, if ongoing inspections in accordance with GL 88-01, as performed under the BWR Stress Corrosion Cracking program, have confirmed IGSCC or SCC indications on RWCU system welds inboard of the primary containment isolation valves, then an additional sample of RWCU system welds outboard of the primary containment isolation valves will be examined based on the requirements of GL 88-01.

Staff Evaluation. During its audit, 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.M25.

Based on its audit of the applicant's BWR Reactor Water Cleanup System program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M25.

Operating Experience. LRA Section B.2.1.16 summarizes operating experience related to the BWR Reactor Water Cleanup System program. The LRA states that ongoing inspections of the RWCU system welds inboard of the RWCU system containment isolation valves have not identified IGSCC or SCC. The LRA also states that no inspection of the outboard RWCU system piping is required for LGS Units 1 and 2. No inspections are required for LGS Unit 1, based on the satisfactory completion of all required actions in GL 89-10, "Safety-Related Motor-Operated Valve Testing and Surveillance," dated June 28, 1989; no IGSCC detected in RWCU system piping welds inboard of the second primary containment isolation valves; and no IGSCC detected in RWCU system piping welds outboard of the second primary containment isolation valves after inspecting a minimum of 10 percent of the susceptible welds. The LRA states that no inspections are required for LGS Unit 2, based on the satisfactory completion of all required actions in GL 89-10 and the use of IGSCC-resistant piping materials.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.16 provides the UFSAR supplement for the BWR Reactor Water Cleanup System program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 BWR Reactor Water Cleanup System program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.11 Reactor Vessel Surveillance

Summary of Technical Information in the Application. LRA Section B.2.1.21 describes the existing Reactor Vessel Surveillance program as consistent with GALL Report AMP XI.M31,"Reactor Vessel Surveillance." LGS Units 1 and 2 use the BWRVIP Integrated Surveillance Program (ISP) to monitor the effects of neutron embrittlement in the RPV beltline materials. The program satisfies the requirements of 10 CFR Part 50, Appendix H, "Reactor Vessel Material Surveillance Program Requirements." The Reactor Vessel Surveillance program is based on the BWRVIP-86-A, "BWR Vessel and Internals Project, BWR Integrated Surveillance Program (ISP) Implementation," and BWRVIP-116 report, "BWR Vessel Internals Project Integrated Surveillance Program Implementation for License Renewal" reports.

The BWRVIP-116 report identifies and schedules additional capsules to be withdrawn and tested during the period of extended operation. LGS Units 1 and 2 will continue to participate in the ISP during the period of extended operation by implementing the requirements of the BWRVIP-116 report. This revised BWRVIP ISP is consistent with 10 CFR Part 50, Appendix H, and it will give reasonable assurance that the fracture toughness requirements of 10 CFR Part 50, Appendix G, will be met through the period of extended operation.

Staff Evaluation. Appendix H of 10 CFR Part 50 specifies surveillance program criteria for 40 years of operation. GALL Report AMP XI.M31 specifies additional criteria for 60 years of operation. The staff determined that compliance with 10 CFR Part 50, Appendix H criteria for capsule design, location, specimens, test procedures, and reporting remains appropriate for this AMP because these items, which satisfy 10 CFR Part 50, Appendix H, will stay the same throughout the period of extended operation.

The staff reviewed LRA B.2.1.21 to determine whether the AMP is adequate to manage the aging effects for which it is credited. During its review, the staff confirmed the applicant's claim of consistency with the GALL Report. The LRA states that the AMP addresses irradiation embrittlement of the RPV beltline and extended beltline materials through testing that monitors the properties of the materials. The LRA stated that the Reactor Vessel Surveillance program will follow the requirements of the BWRVIP ISP and will apply the BWRVIP ISP data to LGS Units 1 and 2.

For the current period of operation, the applicant has implemented the BWRVIP ISP, which is based on the BWRVIP-86-A report. This report is consistent with GALL Report AMP XI.M31 for the current period of operation. For the current license period, the staff had concluded that the BWRVIP ISP in BWRVIP-86-A is acceptable for BWR applicant implementation provided that all participating applicants use one or more of the compatible neutron fluence methodologies acceptable to the staff for determining surveillance capsule and RPV neutron fluences. The staff's acceptance of the BWRVIP ISP for the current term at LGS is documented in License Amendment 163 for LGS Unit 1 and License Amendment 130 for LGS Unit 2, both dated November 4, 2003.

For the period of extended operation, the applicant has stated that the existing program will be consistent with GALL Report AMP XI.M31 by implementing BWRVIP-116. BWRVIP-116 provides guidelines for the ISP to monitor neutron irradiation embrittlement of the RPV beltline materials for all U.S. BWR power plants for the period of extended operation.

Based on its audit of the Reactor Vessel Surveillance program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.31.

Operating Experience. LRA Section B.2.1.21 summarizes operating experience related to the Reactor Vessel Surveillance program. The staff notes that the plants are part of the BWRVIP ISP and that LGS Units 1 and 2 are not required to withdraw any capsules during the period of extended operation. The applicant cited the plants' evaluation of results from the BWRVIP ISP, reported in BWRVIP-135, to demonstrate that the materials met the requirements for continued safe operation. The evaluation results also provide evidence that the existing Reactor Vessel Surveillance program will be capable of monitoring the aging effects associated with the loss of fracture toughness caused by neutron irradiation embrittlement of the RPV beltline materials. The staff concurred with the applicant's conclusion as supported by the staff's approval of the current reflood thermal shock evaluation and pressure-temperature (P-T) limits (see Sections 4.2.7 and 4.2.4 of this SER) using information from all surveillance data in accordance with RG 1.99, Revision 2.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.21 provides the UFSAR supplement for the Reactor Vessel Surveillance Program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 Reactor Vessel Surveillance program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.12 One-Time Inspection

Summary of Technical Information in the Application. LRA Section B.2.1.22 describes the new One-Time Inspection program as consistent with GALL Report AMP XI.M32, "One-Time Inspection." The LRA states that the program manages the aging effects of loss of material, cracking, and loss of heat transfer in metallic piping, piping components, piping elements, and heat exchangers. The LRA also states that the program proposes to manage these aging effects through inspections focused on areas that are most susceptible to aging because of time in service and severity of operating conditions, such as regions isolated from the main flow stream with low flow or stagnant conditions.

Staff Evaluation. During its audit, 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.M32.

Based on its audit of the One-Time Inspection program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M32.

Operating Experience. LRA Section B.2.1.22 summarizes operating experience related to the One-Time Inspection program. The LRA states operating experience for this new program that demonstrates that inspection, identification and corrective action steps for components within AMR are readily available for this program's use and implementation before the period of extended operation.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.22 provides the UFSAR supplement for the One-Time Inspection program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No 22) to implement the new One-Time Inspection program before entering the period of extended operation for managing aging of applicable components and to perform the one-time inspections within the 10 years 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 One-Time Inspection program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.13 Selective Leaching

Summary of Technical Information in the Application. LRA Section B.2.1.23 describes the new Selective Leaching program as consistent with GALL Report AMP XI.M33, "Selective Leaching of Materials." The LRA states that the program manages loss of material because of selective leaching for copper alloy with greater than 15 percent zinc and gray cast iron piping and fittings, valve bodies, pump casings, heat exchanger components, tanks, and fire hydrants exposed to raw water, treated water, closed cycle cooling water, waste water, and soil. The LRA also states that the program will provide for one-time inspections of a representative sample of susceptible components using visual inspections, and hardness tests or other appropriate mechanical examinations, to identify and confirm existence of the loss of material because of selective leaching. The LRA states that the Selective Leaching program will be implemented before the period of extended operation, and that the one-time inspections will be performed within the 5 years before entering the period of extended operation.

Staff Evaluation. During its audit, 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.M33.

For the "acceptance criteria" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "acceptance criteria" program element in GALL Report AMP XI.M33 recommends that there be no visible evidence of selective leaching or no more than a 20 percent decrease in hardness. For copper alloys with greater than 15 percent zinc, the criterion is no noticeable change in color from the normal yellow color to the reddish copper color. The LRA program basis document for the Selective Leaching program states similar acceptance criteria. The applicant also proposes to use alternative mechanical examination techniques for which the hardness testing acceptance criterion is not applicable. By letter dated January 17, 2012, the staff issued RAI B.2.1.23-1 requesting the applicant to state what acceptance criterion will be used when alternative mechanical examination techniques are implemented.

In its response, provided by letter dated February 15, 2012, the applicant stated that the alternative mechanical examinations, such as chipping or scraping, would be used where hardness testing cannot be performed. The applicant further stated that the chipping or scraping of the inspected surfaces would expose signs of selective leaching. These signs can be visually inspected because selective leaching leaves behind a porous material with voids and rust or a weakened and corroded structure. Therefore, the acceptance criterion of "no visible signs of selective leaching" will be used when the alternative mechanical examination techniques are applied.

When selective leaching occurs in gray cast iron, in particular, it is difficult to detect by visual inspection. Therefore, a hardness test or mechanical methods, such as chipping or scraping, are essential for detection of selective leaching. Since the applicant will perform a visual inspection of surfaces where chipping and scraping are used, and if there is any visible sign of selective leaching (e.g., porous material, voids, rust), it will take corrective action, the staff finds the applicant's response acceptable. The staff's concern described in RAI B.2.1.23-1 is resolved.

Based on its audit and review of the Selective Leaching program, and the applicant's response to RAI B.2.1.23-1, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M33.

Operating Experience. LRA Section B.2.1.23 states no occurrences of selective leaching have been identified at LGS to date.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.23 provides the UFSAR supplement for the Selective Leaching program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR contains a commitment (Commitment No. 23) to implement the new Selective Leaching program before entering the period of extended operation, and to perform the one-time inspections for selective leaching of components within the 5 years 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 Selective Leaching program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.14 One-Time Inspection of ASME Code Class 1 Small-Bore Piping

Summary of Technical Information in the Application. LRA Section B.2.1.24 describes the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping program as consistent with GALL Report AMP XI.M35, "One-Time Inspection of ASME Code Class 1 Small-Bore Piping." The LRA states that this program manages cracking of ASME Code Class 1 piping less than 4 inches and greater than or equal to 1-inch nominal pipe size (NPS) in a reactor coolant environment. The LRA also states that the program consists of a one-time volumetric examination of a representative sample of small-bore piping locations susceptible to cracking, which will include both socket welds and butt welds. For socket welds, the LRA states that if a demonstrated volumetric examination technique is not available by the time of the inspections, then destructive examinations will be conducted. In addition, the LRA states that the inspection locations will be based on susceptibility, inspectability, dose considerations, operating experience, and limiting locations of the total population of ASME Code Class 1 small-bore piping.

Staff Evaluation. During its audit, 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.M35. For the "detection of aging effects" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "detection of aging effects" program element in GALL Report AMP XI.M35 recommends that the inspection sample should include 10 percent of the weld population or a maximum of 25 welds of each weld type (e.g., butt welds and socket welds) using a methodology to select the most susceptible and risk-significant welds. However, during its audit, the staff found that the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program does not clearly provide the socket weld population within the scope of the program. Regarding the size of the inspection sample, the LRA states that, for socket weld volumetric examinations, 25 welds at each unit will be examined and the number of welds examined represents "more than 38 percent of the high and medium consequence ranked socket welds." It was not clear to the staff whether the applicant's program is consistent with GALL Report AMP XI.M35 because the staff could not determine the total population of ASME Code Class 1 butt welds and socket welds at each unit within the scope of the program, and how the percentage was calculated. By letter dated November 18, 2011, the staff issued RAI B.2.1.24-1 requesting the applicant to describe the total population of ASME Code Class 1 butt welds and socket welds at each unit within the scope of the program, and to clarify the inspection sample size for socket welds in terms of the percentage of the weld population.

In its response, provided by letter dated December 7, 2011, the applicant described the populations of ASME Code Class 1 small-bore piping welds at each unit. Concerning butt welds, the applicant stated that LGS Unit 1 has 77 and LGS Unit 2 has 84. The applicant stated that it will inspect eight and nine of these welds, respectively, which correspond to greater than 10 percent of the butt weld populations at each unit. Regarding socket welds, the applicant stated that LGS Unit 1 has 85 and LGS Unit 2 has 83 greater than 1-inch NPS and less than

4 inches NPS, and it estimates that there are several hundred socket welds at each unit that are equal to 1-inch NPS. The applicant further stated that the inspection sample size for socket welds at each unit will be 25, which is the maximum inspection size recommended in GALL Report AMP XI.M35. The applicant also revised LRA Section B.2.1.24 to clarify the total populations of butt and socket welds at each unit within the scope of the program and the number of these welds that will be inspected.

Based on its review, the staff finds the applicant's response acceptable because the number of butt and socket welds to be inspected at each unit is consistent with the sampling guidance and recommendations in GALL Report AMP XI.M35. The staff's concern described in RAI B.2.1.24-1 is resolved.

The staff noted that the applicant will implement a risk-informed methodology to select the most susceptible and risk-significant welds. The "detection of aging effects" program element of GALL Report AMP XI.M35 recommends a methodology to select the most susceptible and risk-significant welds. Therefore, the staff finds that the sample selection methodology is consistent with GALL Report AMP XI.M35. The LRA also states that the one-time inspections will be completed within 6 years before the period of extended operation. The staff finds this implementation schedule consistent with the recommendations of the "detection of aging effects" program element of GALL Report AMP XI.M35 regarding timely implementation of the one-time inspections and, therefore, acceptable. The staff determined that aging management of ASME Code Class 1 small-bore piping is adequately addressed because the scope of the program, number of welds to be inspected, selection methodology, and the timely implementation of the small-bore piping inspection are consistent with the recommendations in the GALL Report.

Based on its audit, and review of the applicant's response to RAI B.2.1.24-1, of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M35.

Operating Experience. LRA Section B.2.1.24 summarizes operating experience related to the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program. The LRA indicates that this program is based on relevant plant and industry operating experience. The applicant provided some plant-specific operating experience in the LRA. The LRA states that there was one case in which the applicant detected a small leak from a LGS Unit 2 reactor vessel instrumentation nozzle in the nozzle safe-end to piping socket weld during an outage inspection in 1997. The applicant performed a metallurgical analysis and an evaluation of the crack and determined that it was caused by improper fit-up during the weld installation. As part of its corrective actions, the applicant replaced the affected piping and performed inspection on all similar instrumentation nozzles at both LGS Unit 1 and LGS Unit 2. No additional adverse conditions were identified from the inspection. The applicant further stated that no cracking has since been observed for ASME Code Class 1 small-bore pipe welds.

The staff noted that the applicant has performed design changes to mitigate the cause of failure, performed additional inspections to determine the extent of condition, and implemented corrective actions to prevent recurrence, and that there have not been any similar failures since the small leak detected during the 1997 outage inspection. Therefore, consistent with GALL Report AMP XI.M35, the use of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is still applicable because this previous failure was successfully mitigated.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicant reviewed applicable aging effects and industry and plant-specific operating experience. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.24 provides the UFSAR supplement for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1 and noted that the recommended description includes the statement: "Should evidence of cracking be revealed by a one-time inspection, periodic inspection is also proposed, as managed by a plant-specific AMP." However, the UFSAR supplement for the program, as described in LRA Section A.2.1.24, does not include any statement on actions to be taken in the event that evidence of cracking is revealed by the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program. The licensing basis for this program for the period of extended operation may not be adequate if the applicant does not incorporate this information into its UFSAR supplement. By letter dated November 18, 2011, the staff issued RAI B.2.1.24-2 requesting the applicant to amend the UFSAR supplement to indicate that, if evidence of cracking is revealed by the program, periodic inspections will be implemented under a plant-specific AMP.

In its response, provided by letter dated.December 7, 2011, the applicant revised LRA Section A.2.1.24 to include the statement: "A plant-specific periodic inspection program will be implemented if evidence of cracking caused by IGSCC or fatigue is revealed in ASME Class 1 small-bore piping." The staff finds the applicant's response acceptable because the description in the UFSAR supplement, as amended, adequately captures the need to implement a plant-specific periodic inspection program to manage aging during the period of extended operation if cracking is revealed in ASME Code Class 1 small-bore piping. Therefore, the UFSAR supplement for the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is consistent with the corresponding program description in SRP-LR Table 3.0-1. The staff's concern described in RAI B.2.1.24-2 is resolved.

The staff also noted that the UFSAR supplement contains a comrnitment (Commitment No. 24) to implement the new One-Time Inspection of ASME Code Class 1 Small-Bore Piping program before entering the period of extended operation and perform one-time inspections within the 6 years before the period of extended operation for managing aging of applicable components.

The staff finds that the information in the UFSAR supplement, as amended by letter dated December 7, 2011, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.15 External Surfaces Monitoring of Mechanical Components

Summary of Technical Information in the Application. LRA Section B.2.1.25 describes the new External Surfaces Monitoring of Mechanical Components program as consistent with GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components." The LRA states that the program directs visual inspections of external surfaces of components to be performed during system inspections and walkdowns. The LRA also states that the program consists of periodic visual inspection of metallic and elastomeric components such as piping, piping components, ducting, and other components. The LRA further states that the program will also include visual inspections augmented by physical manipulation as necessary for evidence of hardening and loss of strength.

Staff Evaluation. During its audit, 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.M36. For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "scope of program" program element in GALL Report AMP XI.M36 recommends that the program manages cracking of stainless steel components exposed to an air environment containing halides. However, during its audit, the staff found that the applicant's program does not state that it manages cracking nor does it include inspections of stainless steel components in auxiliary systems for cracking. The staff issued RAI B.2.1.25-1 to address this concern. The applicant's response to this RAI and the staff's evaluation is documented in SER Sections 3.3.2.2.3 and 3.4.2.2.2.

Operating Experience. LRA Section B2.1.25 summarizes operating experience related to the External Surfaces Monitoring of Mechanical Components program.

- In 2008, a comprehensive inspection of external surfaces on LGS plant systems was conducted. The purpose of the LGS inspection was to identify and resolve degraded conditions on piping systems where unprotected or uncoated carbon steel piping was exposed to a wet environment. Results of the inspection indicated that the components were in good condition. Some occurrences of exterior corrosion were identified; these issues were entered into the CAP. Surfaces were cleaned or recoated as necessary.
- During a routine walkdown in 2008, corrosion was identified on the LGS Unit 2 D22 emergency diesel generator (EDG) jacket water heat exchanger outlet piping at a location where the external coating was no longer present. The issue was entered into the CAP, and a work order was generated to correct the condition. These surfaces were repainted.

- During a visual inspection in 2003, a LGS Unit 2 circulating water system elastomer expansion joint was observed to have abnormal bulges indicating that the component is degraded. The issue was entered into the CAP. An engineered replacement was installed, followup actions were developed, and an extent of condition review was performed.
- In 2007, an issue report was generated to document 15 compressed air system carbon steel drain lines that were severely corroded. This issue was entered into the CAP, and the corroded lines were replaced.
- In 2007, an issue report was generated to document a degraded flexible boot on a ventilation exhaust fan discharge line. This issue was entered into the CAP, and a new flexible boot was installed.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.25 provides the UFSAR supplement for the External Surfaces Monitoring for Mechanical Components program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 25) to implement the new External Surfaces Monitoring for Mechanical Components before entering the period of extended operation for managing aging of applicable components. 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 External Surfaces Monitoring for Mechanical Components program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.16 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components

Summary of Technical Information in the Application. LRA Section B.2.1.26 describes the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program as consistent with GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." The LRA states that the program addresses metallic and polymeric piping, piping elements and piping components, ducting components, tanks, heat exchangers, elastomers, and other components exposed to air/gas wetted, closed cycle cooling water, diesel exhaust, fuel oil, lubricating oil, raw water, treated water and waste water environments to manage the effects of loss of material for metallic and elastomeric components, loss of fracture toughness, reduction of heat transfer, cracking, and hardening and loss of strength for elastomers. The LRA also states that the program will manage these aging effects through visual inspections of component internal surfaces when surfaces are made accessible during surveillances, maintenance, and scheduled outages. The LRA further states that for flexible elastomers, the visual inspections will be augmented by physical manipulation.

Staff Evaluation. During its audit, 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.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components." For the "scope of program" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "scope of program" program element in GALL Report AMP XI.M38 recommends that the aging effects included in the program's scope are to be inclusive of all those to be managed within the program. However, during its audit, the staff found that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program omits the aging effects of loss of fracture toughness and reduction of heat transfer and cracking associated with Table 2 items in the LRA. By letter dated January 17, 2012, the staff issued RAI B.2.1.26-1 requesting the applicant to revise the LRA AMP to include the program's aging effects of loss of fracture toughness and reduction of heat transfer and cracking. The applicant also was requested to including the appropriate details, such as parameters to be monitored, acceptance criteria, and detection of aging effect elements necessary to support these program's additional aging effects.

In its response, provided by letter dated February 15, 2012, the applicant stated that LRA AMP B.2.126 and LRA UFSAR supplement Section A.2.1.26 were revised (per Enclosure B of the letter) and loss of fracture toughness and reduction of heat transfer and cracking were added to those LRA Sections. The applicant also stated that loss of fracture toughness is applied to the ASME Code Class 3, B and C RWCU pump casings not applicable to the requirements of GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)" because that program only applies to ASME Code, Class 1 components. The applicant also stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will use visual inspections for these components to monitor for cracking, which follows the inspection and monitoring guidelines found to manage this aging effect in GALL Report AMP XI.M12, but that could not be applied with these ASME Code, Class 3 components. The applicant also stated that reduction of heat transfer aging effect will be managed for the reactor enclosure and control enclosure ventilation system coolers, and the EDG system combustion air coolers, using visual inspections. The applicant also stated that cracking will be managed for stainless steel components in the waste water exposed to greater than a 140 °F environment. The applicant also stated that since these components are in a more aggressive environment than environments addressed by GALL Report AMP XI.M32, One-Time Inspection program, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be used and visual inspections will be used to manage cracking of stainless steel components in the waste water exposed to greater than 140 °F environment. The staff finds the applicant's response acceptable because the applicant has identified all the aging effects that will be addressed by the program, including loss of fracture toughness, reduction of heat transfer, and cracking and the associated program inspections for these aging effects are adequate methods to manage these aging effects. The staff's concern described in RAI B.2.1.26-1 is resolved.

The "scope of program" program element in GALL Report AMP XI.M38 recommends that the program's scope include "...any water system other than open-cycle cooling water system (XI.M20), closed treated water system (XI.M21A), and fire water system (XI.M27)." However, during its audit, the staff found that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program included components in environments of fuel oil, lube oil, and closed cycle cooling water (i.e., closed treated water). By letter dated January 17, 2012, the staff issued RAI B.2.1.26-2 requesting the applicant to provide a technical justification for this enhancement to GALL Report AMP XI.M38, including how applying this AMP will ensure appropriate preventive actions and aging detection activities will be performed for components exposed to fuel oil, lubricating oil, or located within closed cycle cooling water systems.

In its response, provided by letter dated February 15, 2012, the applicant stated that the components exposed to a fuel oil environment are associated with the dirty fuel oil portion of the EDG system and the fuel oil drain tank's associated piping and valves that are beyond the boundary and preventative measures of GALL Report AMP XI.M30 "Fuel Oil Chemistry," which, therefore, would not be effective to manage this aging effect. The applicant also stated that these component environments have similar attributes of the waste water environments monitored by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. This program already includes visual inspection of metallic components, which is effective in identifying loss of material because of corrosion and it is why this program was selected for the fuel oil environment components.

The applicant also stated that the components exposed to a lubricating oil environment are the elastomeric hoses in the lube oil portion of the EDG system that may indirectly benefit from the Lubricating Oil Analysis program, but which would not address aging effects associated with elastomeric components and would not be effective in managing this aging. The applicant also stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program already includes visual inspection and manual manipulation of elastomeric components that effectively identifies hardening and loss of strength caused by elastomeric degradation, which is why this program was selected to manage these components consistent with the GALL Report.

The applicant also stated that the components exposed to a closed treated water environment are the hoses in the jacket cooling water portion of the EDG system. The GALL Report, in AMR item VII.C2.AP-259, recommends the use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage hardening and loss of strength caused by elastomeric degradation of components in a closed-cycle cooling water environment. The applicant also stated that these components may indirectly benefit from preventive measures in the Closed Treated Water Systems program. However, that program does not address aging effects associated with elastomeric components, whereas the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program already includes visual inspection and manual manipulation of elastomeric components effective in identifying hardening and loss of strength caused by elastomeric degradation, which is why this program was selected to manage these components consistent with the GALL Report.

The staff finds the applicant's response acceptable because the measures within the Fuel Oil Chemistry, Lubricating Oil Analysis, or Closed Treated Water Systems programs are not applicable to manage the aging effects for the components discussed above; however, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program does include inspection techniques with suitable and adequate methods for the management of these aging effects involved with these components.

Based on its audit, 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 GALL Report AMP XI.M38.

Operating Experience. LRA Section B.2.1.26 summarizes operating experience related to the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The applicant provided relevant operating experiences in which internal inspections effectively identified and corrected degraded conditions in conjunction with the use of the CAP. In one example, the applicant discussed internal inspections of the main condenser performed during the refueling outages' routine maintenance. These inspections identified degraded conditions that were entered into the CAP and led to immediate repairs, or operability evaluations followed by scheduled repairs. In another operating experience example, the applicant identified the need to clean the exhaust silencer drain pots for an EDG. The drain pots were cleaned and the issue was placed in the CAP, which led to an extent of condition review and the cleaning of each of the other EDGs' drain pots.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.26 provides the UFSAR supplement for the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 26) to implement the new Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program before entering the period of extended operation for managing aging of applicable components. 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 Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, the staff concludes that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M38. The staff concludes that the applicant has demonstrated that the effects of aging will be adequately managed so that he 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).

3.0.3.1.17 Lubricating Oil Analysis

Summary of Technical Information in the Application. LRA Section B.2.1.27 describes the existing Lubricating Oil Analysis program as consistent with GALL Report AMP XI.M39, "Lubricating Oil Analysis." The applicant stated that the program provides oil condition monitoring activities to manage loss of material and reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks within the scope of license renewal exposed to a lubricating oil environment. It is further stated that sampling, analysis, and condition monitoring activities identify specific wear products and contamination and determine the physical properties of lubricating oil within operating machinery. The applicant stated that these activities are used to verify that the wear products and contamination levels and the physical properties of the lubricating oil are maintained within acceptable limits to ensure that intended functions are maintained. This program identifies detrimental contaminants such as water, sediments, specific wear elements, and elements from an outside source. The applicant also stated that contaminant levels are trended in the program's database, and recommendations are made when adverse trends are observed.

Staff Evaluation. During its audit, 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.M39.

Based on its audit of the Lubricating Oil Analysis program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M39.

Operating Experience. LRA Section B.2.1.27 summarizes operating experience related to the Lubricating Oil Analysis program.

The applicant provided the following for operating experience:

> The applicant stated that in 2010, an analysis of lubricating oil from the Unit 1, reactor core isolation cooling (RCIC) pump bearings indicated the presence of unexpected additives for the correct grade of lubricating oil. It indicated that zinc, phosphorus and calcium were the additives detected in the oil that is specified for the equipment and all other parameters were in the normal range. An Issue Report was created and it was determined that the most likely source was inadvertent combination of DTE 732 and DTE 26 oil in a container used for

another component. It was stated that an evaluation and consultation with the lubricant supplier was conducted and it was determined that there was no adverse impact to the properties of the oil. The applicant stated that as a result, the RCIC pump bearings were flushed and the oil replaced.
In March 2009, it was reported that an analysis of the lubricating oil for the Unit 1, RCIC turbine indicated an elevated particle count in the alert range for this component. The oil was required to be changed during the next refueling outage per the Oil Analysis Interpretation Guideline. It was stated that the alert range indicated a low probability of damage or failure of equipment and additional monitoring or analysis may have been required. Subsequently, the applicant stated that the RCIC turbine lubrication oil was changed in September 2009.

The applicant stated that in November 2008, the lubrication oil sample results for the "C" Schuylkill River makeup pump motor indicated high viscosity. It was reported that the viscosity for the upper bearing oil was in the fault range and the lower bearing was just below the alert range. The applicant stated that the high viscosity indicates that the oil is approaching the end of life. The applicant stated that a recommendation was made to replace the oil.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.27 provides the UFSAR supplement for the Lubricating Oil Analysis program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 Lubricating Oil Analysis program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.18 10 CFR Part 50, Appendix J

Summary of Technical Information in the Application. LRA Section B.2.1.33 revised by a letter dated March 20, 2012, describes the existing 10 CFR Part 50, Appendix J condition monitoring program as consistent with GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J." The LRA states that the program addresses the containment steel structures, concrete embedments, penetration sleeves/pressure boundary access points, hatches, airlock, bolting, exposed to indoor air and treated water environments to manage the effects of loss of material, loss of sealing/degradation of gaskets, leakage, and loss of bolt preload. The LRA also states that the program proposes to manage these aging effects through containment leak-rate tests (LRTs) in accordance with the 10 CFR Part 50, Appendix J, "Primary Reactor Containment Leakage Testing for Water-Cooled Power Reactors," on a performance-based approach (Option B) for the testing frequency. The LRTs are performed in accordance with NRC RG 1.163 "Performance-Based Containment Leak-Test Program," NEI 94-01 "Industry Guidance for Implementing Performance-Based Options of 10 CFR Part 50, Appendix J," and ANSI/ANS 56.8, "Containment System Leakage Testing Requirements." The LRTs are performed to assure that the leakage through the primary containment and systems and components penetrating primary containment will not exceed allowable limits specified in Technical Specifications. An integrated leak rate test (ILRT) is performed during a period of reactor shutdown, and local leak rate tests (LLRTs) are performed on isolation valves and containment access penetrations not to exceed 10 CFR Part 50, Appendix J, Option B specified frequencies.

Staff Evaluation. During its audit, 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.S4. For the "scope of program," and "detection of aging effects," program elements, the staff determined the need for additional information, which resulted in the issuance of three RAIs as discussed below.

The "scope of program" program element in GALL Report AMP XI.S4 recommends to include in the LRTs all of the containment boundary pressure-retaining components. However, during the audit the applicant stated that certain components subjected to Type B and C tests have been exempted/excluded from the 10 CFR Part 50, Appendix J LLRTs. The original staff evaluation of the exemptions from the requirements of 10 CFR Part 50, Appendix J testing are contained in the LGS Units 1 and 2 SER and its Supplement 3, dated August 1983. The NRC, by letter dated August 8, 1985, approved certain exemptions for LGS Unit 1 (LGS Unit 2 became operational in 1989 and has the same exemptions) and letter dated February 8, 1996 eliminated requirements for certain Type C components from the 10 CFR Part 50, Appendix J testing for LGS Units 1 and 2. The applicant stated that during the period of extended operation they intend to manage aging effects for these exempted/excluded components through other AMPs. It was not clear to the staff which AMPs the applicant would use to manage the aging effects for the exempted/excluded components. By letter dated January 30, 2012, the staff issued RAI B.2.1.33-1 requesting the exempted or excluded components (valves, penetrations, and other components) from the 10 CFR Part 50, Appendix J program to be identified along with the basis for their exemption or exclusion and the proposed AMPs to be used to manage the applicable aging effects during the period of extended operation.

In its response to RAI B.2.1.33-1, dated February 28, 2012, the applicant stated that the components that are exempted from both LGS Unit 1 and Unit 2 are the traversing in-core probe (TIP) system shear valves. The applicant stated that these valves are the outboard isolation valves for containment penetrations 35C-G. Type C LLRTs of the shear valves are not practical because squib detonation is required for closure. Instead, the applicant proposes to manage the aging effects for the TIP system shear valves by the Compressed Air Monitoring program. In addition the applicant stated that it has excluded penetration number 240 and the associated components from LLRTs. The associated components of the penetration, consist of a suppression pool water seal inboard isolation barrier, a blind flange outboard isolation barrier, and a closed system outside containment. The applicant justified this exclusion by stating that the blind flange is not exposed to the primary containment atmosphere because the line terminates below the minimum water level of the suppression pool and hence there would be a water seal in the case of LOCA, thus excluding the necessity for 10 CFR Part 50, Appendix J LLRT. The applicant proposes to manage aging effects for the excluded components associated with penetration number 240 and included in the LRA Table 3.2.2-5, "Residual Heat Removal (RHR) System Summary of Aging Management Evaluation," with the Bolting Integrity program for bolting, and the External Surfaces Monitoring of Mechanical Components, Water Chemistry, and One-Time Inspection programs for piping, piping components, piping elements, and valves.

The applicant also stated in its response to RAI B.2.1.33-1, that certain isolation valves, identified in UFSAR Table 6.2-25, "Containment Penetrations Compliance with 10 CFR 50, Appendix J," have been excluded from 10 CFR Part 50, Appendix J program LLRTs. The applicant proposed to manage the aging effects for the excluded valves with the External Surfaces Monitoring of Mechanical Components, the Water Chemistry, and the One-Time Inspection programs. The valves excluded from LLRTs are the RHR system isolation valves associated with penetrations 203 A-D, 204A and B, 226A and B, 238, 239; the CS system isolation valves associated with penetrations 206A-D, 207A and B, 208B; and 235, the HPCI system isolation valves associated with penetrations 209, 210, 212, and 236; and the RCIC system isolation valves associated with penetration 214, 215, and 216.

The staff reviewed Table 6.2-25 of the UFSAR and the applicant's response to RAI B.2.1.33-1, and confirmed that for all penetrations (with the exception of penetration 240) that "[t]he isolation provisions consist of a suppression pool water seal, at least one isolation valve outside containment, and a closed system outside containment." The UFSAR also states that "[t]he isolation valve is not exposed to the primary containment atmosphere because the line terminates below the minimum water level of the suppression pool. The closed system is missile-protected, seismic Category I, quality group B, and designed to the temperature and pressure conditions that the system will encounter post-LOCA." For penetrations 238 and 239 associated with the RHR system relief valves, the staff noted that Table 6.2-25, Note 23 of the UFSAR, indicates that through modifications performed at the first refueling the relief valve discharge line isolation valves are also subject either to local testing or removal and bench testing for subsequent LLRTs. Penetrations 238 and 239 are comprised by a "Double O-Ring with Seal Assembly," where typically, the seals per Table 6.2-25, Note 23 of the UFSAR, will be leak rate tested by pressurizing between the O-Rings. For penetration 240, the staff noted that Table 6.2-25, of the UFSAR does not list any valves. The applicant responded that this penetration is subject to Type A ILRT.

The staff determined that the applicant's plans to manage the capacity of leak tightness and associated aging effects of the exempted/excluded containment pressure boundary components through mechanical programs consistent with the GALL Report and acceptable, because they will monitor age-related pressure boundary degradation loss of material, loss of sealing, loss of leak tightness, and loss of bolting preload. The staff's concern described in RAI B.2.1.33-1 is resolved.

The staff noted discrepancies that affect the "scope of program" program element between the UFSAR Tables that include the containment boundary pressure retaining components subject to LLRTs and the Technical Requirements Manual (TRM) containing the plant's testing requirements. The staff also noted a condition report recognizing discrepancies between the UFSAR and the TRM documentation. It is to be noted that the "scope of program" program element in GALL Report AMP XI.S4 includes the LRTs of all of the containment boundary pressure-retaining components. Although, the discrepancies are being tracked by the applicant, it was not clear which document, the UFSAR or the TRM, the applicant would use for the 10 CFR Part 50, Appendix J program testing of systems and components (SCs) during the period of extended operation. By letter dated March 9, 2012, the staff issued RAI B.2.1.33-3, requesting the applicant to identify which document would be followed for testing of SCs during the period of extended operation. The staff also requested the applicant to update the LRA to reflect the document to be followed during the implementation of the 10 CFR Part 50, Appendix J program testing.

In its response to RAI B.2.1.33-3, dated March 20, 2012 the applicant stated that for LGS Units 1 and Unit 2, neither the UFSAR nor the TRM are to be used to provide listing of Type A, B, and C for leak rate testing of SCs during the period of extended operation. The applicant also stated that the discrepancies in these documents are resolved. The leak rate testing of SCs follows the plant test procedures, which are based on the licensing basis described in the UFSAR and TRM. In addition, the applicant revised the program description to indicate that plant procedures are the governing documents for administering the LRTs.

The staff reviewed the applicant's response to RAI B.2.1.33-3 and noted that the revised program description stating that the "[c]ontainment leak rate tests are performed using plant procedures," is acceptable, because the applicant has appropriately designated the plant procedures to identify and control all SCs subject to LRTs and their status during testing. The staff's concern described in RAI B.2.1.33-3 is resolved.

The "detection of aging effects" program element in GALL Report AMP XI.S4 states that while the calculation of leakage rates and satisfactory performance of containment leakage rate testing demonstrates the leak-tightness and structural integrity of the containment, it does not by itself provide information that would indicate that aging degradation has initiated or that the capacity of the containment may have been reduced. The NRC through generic Information Notices (INs), identified conditions that could impact leak tightness and aging degradation of the containment boundary pressure-retaining SCs. IN 2005-23 "Vibration Induced Degradation of Butterfly Valves," and IN 2006-15 "Vibration Induced Degradation and Failure of Safety-Related Valves," have been issued stating that vibration induced stress, wear, and degradation could involve leakage and other long-term effects that could affect valve operation. The staff also noted that the plant's operating experience database indicated that LGS, Unit 2 main steam isolation valve (MSIV) experienced vibration and or shuddering. It was not clear how these INs were addressed and resolved by the applicant. By letter dated March 9, 2012, the staff issued RAI B.2.1.33-2, requesting the applicant to describe how IN 2005-23 and IN 2006-15 have been, and will continue to be addressed so that the integrity of potentially affected containment pressure boundary SCs would not be compromised during the period of extended operation.

In its response to RAI B.2.1.33-2, dated March 20, 2012 the applicant stated that LGS Units 1 Unit 2 addressed IN 2005-23 for vibration induced degradation of butterfly valves in water systems and evaluated its applicability to LGS in December of 2006. Containment penetrations X-25, X-26, X-201A, and X-202 are the only LGS penetrations that use butterfly valves for containment isolation valves. The applicant also stated that these penetrations are for the drywell and suppression pool purge supply and exhaust piping, which is an air environment and concluded that these butterfly valves are not susceptible to the vibration induced degradation experienced by butterfly valves in water systems. As for IN 2006-15 which identifies the issue of vibration-induced degradation and failure of safety-related valves, the applicant stated that this has been addressed in the preventive maintenance process, which classifies components based on criticality and service and specifies inspections and inspection frequencies as appropriate. The applicant then referenced its letter dated March 13, 2012, in response to RAI B.1.4-1, addressing operating experience. The staff's evaluation of the applicant response to RAI B.1.4-1 is addressed in SER 3.0.3.5. The RAI response stated that LGS considers internal and external plant operating experience through a broad set of sources that includes Institute of Nuclear Power Operations (INPO) event report operating experience documents, NRC bulletins, generic letters, INs and regulatory issue summaries, as well as topical reports and vendor correspondence (including 10 CFR Part 21 information). It is in this context that the applicant will readdress the specifics of the INs related to vibratory environments in a global setting and in an ongoing basis, capturing new insights on vibration-induced degradation and long-term effects on valves including those activities performed by the 10 CFR Part 50, Appendix J program.

The staff reviewed the applicant's response to RAI B.2.1.33-2 and finds it acceptable, because the applicant continuously reviews its own operating experience, and industrial and regulatory sources as appropriate for the 10 CFR Part 50, Appendix J program. The staff's concern described in RAI B.2.1.33-2 is resolved.

Based on its audit and review of the applicant's responses to RAIs B.2.1.33-1, B.2.1.33-3, B.2.1.33-2 of the 10 CFR Part 50, Appendix J program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S4.

Operating Experience. LRA Section B.2.1.33 summarizes operating experience related to the 10 CFR Part 50, Appendix J program. The applicant demonstrated through the 10 CFR Part 50, Appendix J program test results that the effects of aging are effectively managed. These results show that SCs are adequately maintained, and that the tested SCs are maintained with significant safety margins between the technical specifications allowable leakage rate limits and the as-tested leakage rates.

Periodic self-assessments of the 10 CFR Part 50, Appendix J program are performed to identify the areas that need improvement to maintain the quality performance of the program. The staff reviewed a 2007 focused area self-assessment for the 10 CFR Part 50, Appendix J program, which considered industry and plant operating experience. The self-assessment concluded that the program was strong, had no deficiencies, and findings were tracked to resolution. This example provides evidence that industry and plant operating experience reviews are performed and that program procedural compliance is achieved.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff

conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.
During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.33 provides the UFSAR supplement for the 10 CFR Part 50, Appendix J program. The staff reviewed this UFSAR supplement description of the program and noted that it conforms to the recommended description for this type of program as described in SRP-LR Table 3.0-1.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its review of the 10 CFR Part 50, Appendix J program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.19 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements.

Summary of Technical Information in the Application. LRA Section B.2.1.38 describes the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program as consistent with GALL Report AMP XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated 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.

Staff Evaluation. During its audit, 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.E1.

Based on its audit of the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E1.

Operating Experience. LRA Section B.2.1.38 summarizes operating experience related to the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program. The applicant stated that regular maintenance inspections have identified cable jacket cracking and embrittlement that were repaired with no loss of function.

The LRA states that in March 2009, during performance of a routine functional check of a level switch for the LGS Unit 2 moisture separator drain tank, it was identified that the outer jacket for the level switch circuit was breaking down and brittle. The wire insulation appeared to be in general good condition. The cable jacket was repaired by standard process using heat shrink electrical tape. The associated switch was found in calibration during post-maintenance testing, confirming circuit integrity.

The LRA also states that in March 2010, during performance of a LGS Unit 1 Limitorque motor operated valve preventive maintenance task on a main steam branch isolation valve, it was identified that the outer jacketing on the power and control cable was cracked and brittle. The cable jacket was repaired by standard process using Raychem sleeving.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the audit report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.38 provides the UFSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 38) to implement the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program before entering 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 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.20 Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits

Summary of Technical Information in the Application. LRA Section B.2.1.39 describes the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program as consistent with GALL Report AMP XI.E2 "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits." The applicant stated the in-scope process radiation monitoring and neutron monitoring circuits are sensitive instrumentation circuits with high-voltage, low-level current signals located in areas where the cables and connections could be exposed to adverse localized environments caused by temperature, radiation, or moisture. The applicant also stated that adverse localized environments can result in reduced insulation resistance causing increases in leakage currents.

Staff Evaluation. During its audit, 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.E2.

Based on its audit, of the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E2.

Operating Experience. LRA Section B.2.1.39 summarizes operating experience related to the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program. The LRA states that in March 2006, it was identified that a LGS Unit 1 low-power range monitor (LPRM) had a defective connector on the under vessel end of the cable that connects the detector to the pull box in the drywell. Troubleshooting identified that the electrical connection under vessel was affecting continuity and causing the less than adequate LPRM performance. The cable and connector were replaced. Subsequent circuit testing was completed and met acceptance criteria.

The LRA also states that in February 2009, during performance of calibration for preventive maintenance it was identified that a LGS Unit 2 intermediate range monitor detector did not meet the acceptance criteria for the I/V (current to voltage) curve test. Troubleshooting was performed, which included direct cable tests of the complete circuit, testing of outboard and inboard penetration connections, testing of under vessel connections, and direct cable tests of the circuit upstream of the under vessel connections. It was determined that the under vessel connection was the cause of not meeting test acceptance criteria. The connection was replaced and post-connection replacement results were satisfactory.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.39 provides the UFSAR supplement for the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualifications Requirements Used in Instrumentation Circuits program.

The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 39) to implement the new Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program before entering the period of extended operation for managing aging of applicable components.

The staff finds that the information in the UFSAR supplement is an adequate summary description of the program.

Conclusion. On the basis of its review of the Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.21 Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.40 describes the new Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program as consistent with GALL Report AMP XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The LRA states that the AMP manages non-environmental qualification (EQ), in-scope, inaccessible power cables exposed to significant moisture. The LRA defined inaccessible power cables for this program as greater than or equal to 400 volts. The LRA also states that the in-scope cables of this program will be tested at least once every 6 years using a proven test for detecting deterioration of the insulation system because of significant moisture. The first tests will be completed before the period of extended operation.

The LRA stated that inspection for water collection in manholes with subsequent corrective actions (e.g., water removal), as necessary will be performed at least annually. The LRA also states that before the period of extended operation, the frequency of inspections for accumulated water will be established and adjusted based on plant-specific inspection results. The LRA further stated that the operation of dewatering devices will be confirmed before any known or predicted heavy rain or flooding event. The LRA further states that the first inspections are to be completed before the period of extended operation.

Staff Evaluation. During its audit, 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.E3.

For the "preventive actions" and "detection of aging effects" program element, LRA Table 2.5.2-1, and the applicant's draft procedure for implementing the program, the staff determined the need for additional information, which resulted in the issuance of RAIs as discussed below.

GALL Report AMP XI.E3 recommends periodic actions to be taken to prevent inaccessible power cables from being exposed to significant moisture, such as identifying and inspecting accessible cable conduit ends and cable manholes within the scope of license renewal for water collection and draining the water, as needed.

However, during its audit, the staff found that the applicant's program description and "preventive action" program element of the applicant's program basis document, LRA Sections A.2.1.40, and B.2.1.40, and LRA Table A.5, Commitment No. 40, are not consistent in describing the applicant's program to manage inaccessible power cables subject to significant moisture (e.g., exposed to significant moisture, minimize exposure, and prevent exposing cables to significant moisture). It was not clear that these statements are consistent with GALL Report AMP XI.E3, which recommends that actions be taken to prevent cables from being exposed to significant moisture whereas the applicant's AMP, and LRA, including Sections B.2.1.40 and A.2.1.40, and LRA Table A.5, Commitment No. 40 describe the program as minimizing potential exposure to significant moisture. By letter dated January 30, 2012, the staff issued RAI B.2.1.40-1 requesting that the program basis document, LRA Sections B.2.1.40, and A.2.1.40, and LRA Table A.5, Commitment No. 40 provide consistency with GALL Report AMP XI.E3 in the management of inaccessible power cable exposed to significant moisture.

In its response, dated February 28, 2012, the applicant stated that the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is a new program that is consistent with GALL Report AMP XI.E3. The applicant also stated that inaccessible power cables in the scope of this program may at times be exposed to significant moisture. The applicant stated that these cables will be tested using a proven test for detecting reduced insulation resistance of the cables' insulation system because of wetting or submergence. The applicant further stated that the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40, were revised to clarify that periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Additionally, the applicant stated that the program basis document will also be revised for this clarification.

The staff finds the applicant's response acceptable because LRA Sections B.1.2.40 and A.2.1.40, and LRA Table A.5, Commitment No. 40 were revised consistent with GALL Report AMP XI.E3 such that periodic actions are taken to prevent inaccessible cables from being exposed to significant moisture. In addition, the applicant's program basis document also will be revised to reflect this change. The staff's concern described in RAI B.2.1.40-1 is resolved.

GALL Report item VI.A.LP-35 addresses conductor insulation for inaccessible power cables greater than or equal to 400 volts (e.g., installed in conduit or direct buried) constructed of various organic polymers and recommends GALL Report AMP XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements" to manage reduced insulation resistance caused by moisture.

During its audit, the staff noted that the LRA uses the term "Electrical Continuity" in describing the intended function in LRA Table 2.5.2-1, for the commodity "Insulation Material for Electrical Cables and Connections." LRA Table 3.6.2-1 uses "Electrical Continuity" for the intended function for component types, "Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V," "Fuse Holders (Not Part of Active Equipment): Insulation Material," "Insulation Material for Electrical Cables and Connections," "Insulation Material for Electrical Cables and Connections Used in Instrumentation Circuits," and LRA Section 2.5.2.5.2, "Electrical Penetrations." In addition, component type, "Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements," in LRA Table 3.6.2-1 lists the materials "Various Polymeric and Metallic Materials," and, therefore, also should include the intended function "Insulate (Electrical)." The use of the intended function, "Electrical Continuity" in the above examples is inconsistent with the material (various organic polymers) listed for the component types referenced. By letter dated January 30, 2012, the staff issued RAI B.2.1.40-2 requesting the applicant to provide revised intended functions for LRA Table 2.5.2-1, Insulation Material for Electrical Cables and Connections, and LRA Table 3.6.2-1, Component Types (Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V, Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements, Fuse Holders (Not Part of Active Equipment): Insulation Material, Insulation Material for Electrical Cables and Connections, and Insulation Material for Electrical Cables and Connections Used in Instrumentation Circuits).

In its response, provided by letter dated February 28, 2012, the applicant stated that the intended function for insulation materials subject to an AMR is "Insulate (Electrical)" and LRA Section 2.5.2.5.2 was revised to remove electrical continuity. The applicant also stated that LRA Table 2.5.2-1 was revised to identify the intended function of Insulation Material for Electrical Cables and Connections as "Insulate (Electrical)" and to clarify the name of the fuse holder commodity to "Fuse Holders: Metallic Clamps." In addition, the applicant stated that LRA Table 3.6.2-1 was revised to change the intended functions for insulation material component types to "Insulate (Electrical)" for the following items: Conductor Insulation for Inaccessible Power Cables Greater Than or Equal to 400V, Electrical Equipment Subject to 10 CFR 50.49 EQ Requirements Made of Various Polymeric Materials, Fuse Holders (Not Part of Active Equipment): Insulation Material, Insulation Material for Electrical Cables and Connections, and Insulation Material for Electrical Cables and Connections Used in Instrumentation Circuits.

The staff finds the applicant's response acceptable because LRA Section 2.5.2.5.2 has been clarified with regard to intended function and LRA Tables 2.5.2-1 and 3.6.2-1 have been revised to change the intended functions for insulation material to "Insulate (Electrical)," making the use of "Insulate (Electrical)" consistent with the material listed for the component types referenced. The staff's concern described in RAI B.2.1.40-2 is resolved.

GALL Report AMP XI.E3 recommends that inaccessible power cables exposed to significant moisture be tested at a frequency of at least every 6 years, and test frequencies adjusted based on test results and operating experience.

During its audit, the staff noted that draft procedure implementing the program specifies a test frequency of every third refueling outage. The "detection of aging effects" program element of the applicant's AMP basis document states that the testing will be performed every 6 years and does not include a provision that test frequencies are adjusted based on test results and operating experience. It is not clear to the staff that the applicant's program, when implemented, will be consistent with GALL Report AMP XI.E3 such that testing will occur at least every 6 years and more frequent testing will occur based on test results and operating experience. By letter dated January 30, 2012, the staff issued RAI B.2.1.40-3 requesting the applicant to explain why the "detection of aging effects" program element in the applicant's AMP basis document, along with draft work order revisions, specify only a 6-year test interval but do not specify a test frequency of at least every 6 years, and that test frequencies are adjusted based on test results and operating experience. In addition, the staff asked the applicant to explain why LRA Sections A.2.1.40, and B.2.1.40, and LRA Table A.5, Commitment No. 40 specify only a test interval of at least every 6 years but do not specify that test frequencies are adjusted based on test results and operating experience.

In its response, dated February 28, 2012, the applicant stated that the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program including implementing work orders are subjected to the applicant's CAP, in accordance with the "corrective action" program element. The applicant also stated that under the "corrective action" program, unacceptable results are subject to engineering evaluation with the evaluation considering the significance of the test results when determining corrective actions. The applicant stated that one potential corrective action would be more frequent cable testing. The applicant further stated that for clarity and alignment the "detection of aging effects" program element, LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40 were revised to clarify a cable test frequency of at least every 6 years and that more frequent testing may occur based on test results and operating experience. Additionally, the applicant stated that the program basis document and work order revision requests also will be revised for this clarification.

The staff finds the applicant's response acceptable because LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40 have been revised to include a provision that more frequent testing may occur based on test results consistent with GALL Report AMP XI.E3. In addition, the applicant's program basis document will be revised to reflect this change. The staff's concern described in RAI B.2.1.40-3 is resolved.

GALL Report AMP XI.E3, program element "preventive actions," recommends that inspections are performed periodically based on water accumulation over time and for event-driven occurrences, such as heavy rain or flooding.

During its audit, the staff found that the applicant's AMP basis document and LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40 are not consistent with GALL Report AMP XI.E3 in that event-driven inspection (e.g., for heavy rain or flooding events) are not specified to be performed. By letter dated January 30, 2012, the staff issued RAI B.2.1.40-4 requesting the applicant to explain why the AMP basis document, LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40 do not specify inspections will be performed for event-driven occurrences.

In its response, dated February 28, 2012, the applicant stated that the "preventive actions" program element for the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40 were revised to include a provision that the inspection frequency for manholes will be established and performed based on water accumulation over time and event-driven occurrences, such as heavy rain or flooding. The applicant also stated that the program basis document will be revised to include this change.

The staff finds the applicant's response acceptable because LRA Sections A.2.1.40 and B.2.1.40, and LRA Table A.5, Commitment No. 40 has been revised to include a provision that the inspection frequency for manholes will be established and performed based on water accumulation over time and event-driven occurrences, such as heavy rain or flooding, consistent with GALL Report AMP XI.E3. In addition, the applicant's program basis document will be revised to reflect this change. The staff's concern described in RAI B.2.1.40-4 is resolved.

Based on its audit of the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, and review of the applicant's responses to RAIs B.2.1.40-1, B.2.1.40-2, B.2.1.40-3, and B.2.1.40-4, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E3.

Operating Experience. LRA Section B.2.1.40 summarizes operating experience related to the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program. The applicant stated that operating experience examples provide objective evidence that the applicant's program will be effective in ensuring that intended function is maintained consistent with the CLB for the period of extended operation.

A review of the applicant's response to GL 2007-01 indicated that the applicant identified five cable failures. Four of the cable failures were associated with the 13 kV power feeds for circulating water pumps; 1A-P501, 1B-P501, and 1C-P501. Two of the four failures occurred in service while the other two failures were identified during testing. The remaining failure occurred in the feed to the 222 transformer. All of the failures were attributed to manufacturing defects. As stated in the GL 2007-01 response, three of the cable failures occurred in 1995 with one additional failure each in 2000 and 2005. The applicant stated in the LRA that the specific manufacturing defects were caused by voids and impurities in the insulation coupled with operation in a wet environment. The applicant also stated in the LRA that there have been no failures of cables that are in the scope of license renewal. In accordance with the applicant's GL 2007-01 response, as a result of these failures, potentially wetted cables energized at 13.8 kV are now periodically tested. The staff also reviewed integrated inspection reports 05000352/2008005 and 05000353/2008005, dated January 30, 2009; 05000352/2008003 and 05000353/2008003, dated August 13, 2008; and 05000352/2010005 and 05000353/2010005, dated January 24, 2011. In inspection report 05000352/2010005 and 05000353/2010005, the inspectors noted that the applicant experienced three additional cable failures associated with the 122 plant services transformer supply cable, the 144D technical support center transformer power supply cable, and the 222 plant services transformer supply cable. The inspectors also noted two other 13kV power supply cables identified by testing as degraded. Because of recent failures, the applicant planned to expedite cable replacement of known degraded cables and the testing of remaining cables. The three additional cable failures occurred in 2010.

The LRA references significant event notification 272, which documented how a degraded underground cable resulted in a phase-to-ground fault and loss of offsite power to safety-related busses at another plant. The applicant stated that the specific evaluation performed for LGS addressed several factors for cable condition monitoring. As a result of this evaluation, LGS identified and documented its inaccessible medium voltage cables, cable functions, and the associated potential consequence of failure. The evaluation also identified cable testing strategies and preparedness for cable replacement.

The LRA also notes that a 2009 inspection of nonsafety-related manholes identified degradation of supports and internal commodities because of water intrusion. The LRA states that additional inspections were performed for three other manholes and water intrusion was observed in them. The applicant stated that a dewatering plan for these four manholes, as well as the other 40 manholes, was developed that included actions to initiate modification for sump pumps or other dewatering devices for manholes susceptible to water intrusion.

The applicant also stated in the LRA that in 2010, corporatewide actions were initiated to identify cables subject to wetting and to assess and subsequently improve associated manhole configurations. The applicant further stated that corrective actions include: (1) identifying inaccessible underground cables, (2) identifying which of these cables are in-scope for maintenance rule or license renewal, (3) identifying current inspection or dewatering strategy for underground structures and manholes, (4) developing a schedule for inspections and, if needed, dewatering, (5) ranking cables routed in underground structures and manholes with respect to their safety or generation critical functions, and (6) developing a long-term plan for condition monitoring of safety-related or generation critical cables routed in underground structures considering testing, rerouting, or replacement. The applicant further stated that these corrective actions are currently in progress.

During the audit, the staff walked down nonsafety manhole MH001 located in the protected area. A review of recent work orders (August 2010 through August 2011) for inspection of MH001 indicated that this manhole has a history of water intrusion and submerged cable.

The staff also reviewed manhole inspection results for nonsafety and safety-related manholes within the scope of license renewal. The results of these inspections indicate that the nonsafety manholes within the scope of license renewal have experienced water intrusion with cables found submerged, requiring water to be drained from the manhole. A review of safety-related manhole inspection results also indicates that all in-scope safety-related manholes have experienced water intrusion and submerged cables. Applicant corrective actions for the nonsafety manholes include the installation of level transmitters to identify manhole water intrusion, track water intrusion rates, provide level alarms, and establish manhole pump down frequencies, including frequencies for in-scope nonsafety manholes (MH001 and 002). The staff walked down the completed level transmitter system for manhole MH001 and was provided level transmitter data for MH001 from September 20, 2011, to October 13, 2011. The data included level indications, alarm activation, and pump down results. The applicant stated that the level transmitter work orders have been completed and the system installation is complete for nonsafety-related manholes. The applicant also has initiated an action that requests installation of permanent sump pumps for in-scope safety-related manholes.

The applicant has completed cable testing and established recurring task work orders (on a 2-or 3-year schedule, depending on the circuit) for testing of inaccessible medium voltage cable within the scope of license renewal. It also has initiated an action to develop test procedures and implementation for low-voltage power cable within the scope of license renewal.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.40 provides the UFSAR supplement for the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1. The UFSAR supplement provided in LRA Section A.2.1.40 was revised in response to staff RAIs as discussed below.

In its response to RAI B.2.1.40-3, which is discussed above in the "staff evaluation," the applicant stated that for clarity and alignment with the "detection of aging effects" program element, the UFSAR supplement provided in LRA Section A.2.1.40 and LRA Table A.5, Commitment No. 40, were revised to specify a cable test frequency of at least every 6 years and that more frequent testing may occur based on test results and operating experience.

The staff finds the revised UFSAR supplement acceptable because LRA Section A.2.1.40 and LRA Table A.5, Commitment No. 40, have been revised to include a provision that more frequent testing may occur based on test results consistent with GALL Report AMP XI.E3.

In its response to RAI B.2.1.40-4, which is discussed above in the "staff evaluation," the applicant revised the UFSAR supplement in LRA Section A.2.1.40 and LRA Table A.5, Commitment No. 40 to include a provision that the inspection frequency for manholes will be established and performed based on water accumulation over time and event-driven occurrences, such as heavy rain or flooding.

The staff finds the revised UFSAR supplement acceptable because LRA Section A.2.1.40 and LRA Table A.5, Commitment No. 40, were revised to include a provision that the inspection frequency for manholes will be established and performed based on water accumulation over time and event-driven occurrences, such as heavy rain or flooding, consistent with GALL Report AMP XI.E3.

Based on its review of the LRA, and the applicant's response to RAI B.2.1.40-3 and RAI B.2.1.40-4, the staff finds that the UFSAR supplement for the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program is consistent with the corresponding program description in SRP-LR Table 3.0-1.

The staff also noted that the UFSAR contains a commitment (Commitment No. 40) to implement the new Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program before entering the period of extended operation for managing aging of applicable components.
The staff finds that the information in the UFSAR supplement, as amended by letter dated February 28, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.22 Metal Enclosed Bus

Summary of Technical Information in the Application. LRA Section B.2.1.41 describes the new Metal Enclosed Bus program as consistent with GALL Report AMP XI.E4, "Metal Enclosed Bus." The LRA states that the Metal Enclosed Bus program is a new program that will be used to manage aging of in-scope metal-enclosed bus during the period of extended operation. The internal portions of the bus enclosure assemblies will be inspected for cracks, corrosion, foreign debris, excessive dust buildup, and evidence of water intrusion. The LRA also stated that bus insulation will be visually inspected for signs of reduced insulation resistance, such as embrittlement, cracking, chipping, melting, discoloration, swelling, or surface contamination. The internal bus insulating supports will be visually inspected for structural integrity and signs of cracks. Enclosure assembly elastomers will be visually inspected for surface cracking, crazing, scuffing, dimensional change, shrinkage, discoloration, hardening, and loss of strength.

Furthermore, the LRA stated that a sample of accessible bolted connections will be inspected for increased resistance of connection using thermography. The sample will be 20 percent of the accessible metal enclosed bus (MEB) bolted connection population with a maximum sample size of 25.

Staff Evaluation. During its audit, 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.E4.

For the "parameters monitored or inspected," and "detection of aging effect" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "parameters monitored or inspected" program element of the applicant's AMP basis document states that it is consistent with the GALL Report XI.E4 AMP. It requires that a sample of accessible bolted connections be inspected for increased resistance using thermography, and not by retorquing. However, the implementing procedure for the program requires bus joint nuts and bolts to be retorqued. EPRI TR-104213s, "Bolted Joint Maintenance and Application Guide," states that bolted joints should be inspected for evidence of overheating, signs of burning or discoloration, and indications of loose bolts. The bolts should not be retorqued, unless the joint either requires service or the bolts are clearly loose. Verifying the torque is not recommended. The torque required to turn the fastener in the tightening direction (restart torque) is not a good indicator of the preload once the fastener is in service. Because of relaxation of the parts of the joint, the final loads are likely to be lower than the installed loads. In addition, the applicant's AMP basis document, as well as GALL Report AMP XI.E4, does not recommend retorquing. The applicant's AMP implementation procedure is not consistent with the program's AMP basis document. The GALL Report recommends measuring the connection resistance of bolted joints using a micro-ohmmeter. By letter dated January 30, 2012, the staff issued RAI B.2.1.41-1, requesting the applicant to provide technical justification of why retorquing of bus connections are a good engineering practice to check for bolt loosening and to clarify the discrepancy between the AMP's basis document and its implementing procedure.

In its response, dated February 28, 2012, the applicant stated that retorquing of metal enclosed bus, bolted bus connections is not part of the LGS Metal Enclosed Bus program. The LGS program will perform thermography of a sample of accessible bolted connections to inspect for increased resistance of bus connections. To implement the Metal Enclosed Bus program, the applicant stated that existing maintenance procedures and work orders will be revised to specifically annotate included license renewal activities, acceptance criteria, and inspection frequency. These procedures also contain activities not part of the Metal Enclosed Bus program. The applicant also stated that drafted revisions to program implementing procedures and work orders do not include annotation of bus connection retorque for license renewal. The applicant further stated that a search of work order history revealed that LGS MEB joint nuts and bolts have not been retorqued to date. This approach is consistent with GALL Report AMP XI.E4 recommendations. The applicant stated that the existing maintenance procedure and work order steps for torque checks do not apply to MEB connections. The applicant stated that because bolted connection retorque has not been performed for MEB connections and is not part of the Metal Enclosed Bus program, technical justification of retorquing of bus connections is not provided. Additionally, the applicant stated that because bolted connection retorque has not been performed for MEB connections and is not part of the Metal Enclosed Bus program, there is no discrepancy between the program basis document and the drafted, annotated portions of the maintenance procedure and work orders that implement the Metal Enclosed Bus program.

The staff finds the applicant's response acceptable because the applicant has confirmed that it has not retorqued MEB bolted connections to date. The applicant will perform thermography on a sample of bolted connections to inspect for increased resistance of bus connections. The program implementing procedures do not include bus connection retorque for license renewal. Additionally, the existing maintenance procedures and work orders will be revised to assure there will be no discrepancy between the program's AMP basis document and the maintenance procedure that implement the Metal Enclosed Bus AMP. The staff's concern described in RAI B.2.1.41-1 is resolved.

The "detection of aging effects" program element of the applicant's AMP basis document states that a sample of the MEB accessible bolted connections in each bus section shall be inspected using thermography for increased resistance. The inspections are performed on all accessible bus sections while the bus is energized. GALL Report AMP XI.E4 recommends inspecting a sample of the accessible bolted connections for increased resistance using thermography or connection resistance measurements. The applicant provided the staff a photograph of thermography showing a heat source from a space heater inside an MEB. However, the applicant did not provide any photographs taken from outside the bus duct showing the temperature difference between the bus connection because of increased resistance. In general, keeping with the best practices, windows normally are installed on the MEB for thermography inspections. The metal enclosed cover and the space heater may mask the heat created by loosening of bus connections and the temperature differences between bus connections that may not be detected if windows are not installed on MEBs. By letter dated January 30, 2012, the staff issued RAI B.2.1.41-2, requesting the applicant to discuss the plant-specific operating experience with thermography taken from outside a bus duct showing the bus connection difference because of bolt loosening. In addition, the staff requested the applicant to discuss the manufacturer's recommendation for inspecting bolted connections from outside a bus enclosure. The staff also requested the applicant to explain how thermography inspection is effective to detect bolted connection for increased resistance.

In its response, dated February 28, 2012, the applicant stated that the operating experience for the MEB within the scope of license renewal is documented in LRA Appendix B, Section B.2.1.41, and in the Metal Enclosed Bus program basis document, element 10, "operating experience." There have been no failures of the 4 kV MEBs within the scope of license renewal at LGS. There is no adverse trend in the associated thermography inspection results for the 4 kV metal enclosed buses within the scope of license renewal at LGS. The applicant further stated that routine maintenance results do not indicate a loosening of MEB connections. Since there is not a thermography picture available of a loose bolted connection for LGS's MEB, a picture of thermography showing a heat source from a space heater inside a MEB was provided during the onsite audit to demonstrate the sensitivity of the thermography equipment to detect heat through the metal enclosure and the emissivity of the enclosure. The applicant stated that there are physical location differences between the bolted connections and the electric heaters. An electric heater is located within a segment of the enclosure, along the outside edge. In contrast, bolted bus connections are located where sections of the MEB are joined together, both the bus and the enclosure. Therefore, electric heaters and bolted connections are not in the same physical location in the MEB. The applicant also stated that the heat signature for an electric heater shows a pinpointed heat source with decreasing temperatures as distance from the center increases. The heat signature for resistance for a loose connection would be ring-like, encircling the bolted connection for the bus bar. The heat signature for the electric heater would not mask or be misinterpreted as a potential degraded connection. The applicant stated that manufacturer's recommendations for testing include factory tests and post-installation tests to ensure no damage from shipping or installation. The applicant also stated that the LGS themography procedure follows established industry practices for thermography. GALL Report AMP XI.E4 and the SRP-LR associated AMP recommendations do not present industry operating experience to counter existing standards and methodology. The applicant further stated that the current thermography inspection methodology is, and will continue to be, effective in detecting increased resistance of bolted connections.

The staff finds the applicant's response acceptable because the applicant has confirmed that plant-specific operating experience has not experienced MEB connection failures and routine maintenance has not indicated a loosening of MEB connections. The applicant also confirmed that the electric heaters and bus connections are in different physical locations. The heat images from the electric heaters will not mask those from the bus connections. The staff finds that current infrared thermography inspection from the outside of bus ducts when the bus is energized is used by the industry as a predictive maintenance program for inspection of MEB connections. The staff also finds that thermography inspection is consistent with GALL Report AMP XI.E4. The staff's concern described in RAI B.2.1.41-2 is resolved.

Based on its audit of the Metal Enclosed Bus program, and review of the applicant's responses to RAIs B.2.1.41-1 and B.2.1.41-2, the staff finds that program elements 1 to 6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E4.

Operating Experience. LRA Section B.2.1.41 summarizes operating experience related to the Metal Enclosed Bus program. The applicant stated that in October 2002, a nuclear event report was issued to Exelon stations for an isophase bus duct insulator failure at another plant. The cause was identified as internal arcing. Fleetwide corrective actions included implementation of hi-pot testing of isophase and nonsegregated metal enclosed buses every 6 years. The applicant also stated that in February 2009, LGS performed an evaluation of industry operating experience for nonsegregated bus degradation at a pressurized-water reactor (PWR). This operating experience item was issued as a result of corrosion found during bus bar inspection. The PWR plant investigation identified that the lack of periodic visual inspections allowed for water intrusion that resulted in degradation and corrosion. The LGS evaluation for applicability identified that previously initiated corporatewide corrective actions for the nuclear event report already had ensured implementation of prudent MEB condition monitoring.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and that the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.41 provides the UFSAR supplement for the Metal Enclosed Bus program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 41) to implement the Metal Enclosed Bus program before entering the period of extended operation for managing aging of applicable components.

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 Metal Enclosed Bus program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.23 Fuse Holders

Summary of Technical Information in the Application. LRA Section B.2.1.42 describes the new Fuse Holders program as consistent with GALL Report AMP XI.E5, "Fuse Holders." The LRA states that the Fuse Holders program applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects. Fuse holders located inside an active device are not within the scope of this program. The program will be used to manage aging of the metallic portions of fuse holders. Stressors managed by this program include frequent manipulation, vibration, chemical contamination, corrosion, oxidation, ohmic heating, thermal cycling, and electrical transients. The LRA also states that 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. The new Fuse Holders program will be implemented before the period of extended operation. In addition, the first tests will be completed before the period of extended operation.

Staff Evaluation. During its audit, 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 elements of GALL Report AMP XI.E5.

Based on its audit, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E5.

Operating Experience. LRA Section B.2.1.42 summarizes operating experience related to the Fuse Holders program. The applicant stated that in April 2004, a LGS Unit 2 drywell cooler drain flow high alarm was received several times. Drywell leakage was confirmed to remain within normal technical specification limits. Investigation identified a defective fuse holder clip. The fuse holder clip was not providing enough force to make good contact with the fuse. The fuse holder clip was repaired, a post-maintenance test was completed with satisfactory results, and the intermittent alarm ceased.

The applicant also stated that in March 2005, main control room indication for a LGS Unit 2 high-pressure coolant injection (HPCI) suppression pool suction valve was lost. Troubleshooting determined that the lost indication may have been because of a fuse failure. The inspection identified a failed fuse block. The lug to leaf joint rivet of the fuse block was deformed. The fuse block was replaced and the component was satisfactorily tested.

The applicant further stated that in October 2009, a LGS Unit 1 reactor enclosure ventilation exhaust radiation monitor alarmed downscale, which resulted in partial containment isolation. After immediate procedural actions, an investigation determined that downscale indication was the result of a broken fuse holder, specifically the Bakelite insulating material. The holder had fractured releasing tension on the fuse, thus preventing electrical contact. The fuse holder, insulating, and metallic parts did not exhibit any discoloration or signs of heating. Subsequent analysis of the fuse holder attributed the failure to tool marks found adjacent to the circumferential fracture. Long-term spring force against the fuse and exercising the fuse holder resulted in failure. The investigation concluded that this damage occurred during initial installation or at the manufacturer's facility. The extent of condition evaluations found another damaged (i.e., chipped) fuse holder that has been scheduled for replacement.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.42 provides the UFSAR supplement for the Fuse Holders program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 42) to implement the new Fuse Holders program before entering the period of extended operation for managing aging of applicable components.

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 Fuse Holder program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.24 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements

Summary of Technical Information in the Application. LRA Section B.2.1.43 describes the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program as consistent with GALL Report AMP XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements." The applicant stated that the program will implement one-time testing of a representative sample of non-EQ electrical cable connections to ensure that either increased resistance of connection does not occur or that the existing preventive maintenance program is effective such that a periodic inspection program is not required. The new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program will be implemented before the period of extended operation.

Staff Evaluation. During its audit, 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.E6.

Based on its audit of the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.E6.

Operating Experience. LRA Section B.2.1.43 summarizes operating experience related to the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program. The applicant stated that in May 2009, elevated temperatures were found during routine thermography on the incoming "B" phase wire to a LGS Unit 1 SLC tank heating element breaker. Troubleshooting identified that the terminal block screw was stripped. The screw was replaced and subsequent thermography confirmed a reduction in temperature, yet the connection required additional action since the delta between "B" phase connection temperature and "A" or "C" phase connection temperatures exceeded condition monitoring thresholds. Increased frequency thermography is being performed to monitor the connection until incoming leads are repaired or replaced. Repair and replacement work is planned and scheduled.

The applicant also stated that in September 2009, elevated temperatures were found during routine thermography on the incoming "A" and "B" phase wires to a LGS Unit 2 drywell area unit cooler breaker. Similarly, in January 2010, elevated temperatures were found during routine thermography on the incoming "A" phase wire to another LGS Unit 2 drywell area unit cooler breaker. Also, in February 2010, elevated temperatures were found during routine thermography on the incoming "B" phase wire to a LGS Unit 1 RHR pump room cooler breaker.

During investigation of the connections, leads were tightened. Post-maintenance thermography connection temperatures were acceptable; no further action was warranted.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience and the program, when implemented, can adequately manage the effects of aging on SSCs within the scope of the program.

UFSAR Supplement. LRA Section A.2.1.43 provides the UFSAR supplement for the Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program. The staff reviewed the UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR contains a commitment (Commitment No. 43) to implement the new Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program before entering the period of extended operation for managing aging of applicable components.

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 Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.1.25 Environmental Qualification (EQ) of Electric Components

Summary of Technical Information in the Application. LRA Section B.3.1.2 describes the existing Environmental Qualification (EQ) of Electric Components program as consistent with GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components." The applicant stated that the program establishes, demonstrates, and documents the level of qualification, qualified configurations, maintenance, surveillance, and component replacements necessary to meet 10 CFR 50.49. The applicant also stated that the program includes electric equipment important to safety that is subject to adverse environment caused by heat, radiation, oxygen, moisture, or voltage.

Staff Evaluation. During its audit, 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 elements of GALL Report AMP X.E1.

Based on its audit, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP X.E1.

Operating Experience. LRA Section B.3.1.2 summarizes operating experience related to the Environmental Qualification (EQ) of Electric Components program. The applicant stated that in August 2005, during increased frequency stroking of LGS Unit 2 CS pump unit cooler valves, the applicant identified that a valve would not open fully. To maintain area temperatures assumed in EQ analyses, the applicant placed a redundant cooler into service to maintain EQ temperatures for the associated CS pump. Corrective actions subsequently returned the cooler valve to service.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program that demonstrates it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.3.1.2 provides the UFSAR supplement for the Environmental Qualification (EQ) of Electric Components program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Section 4.4.3.2. 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 Environmental Qualification (EQ) of Electric Components program, the staff concludes that those program elements for which the applicant claimed consistency with the GALL Report 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).

3.0.3.2 AMPs Consistent with the GALL Report with Exceptions or Enhancements

In LRA Appendix B, the applicant stated that the following AMPs are, or will be, consistent with the GALL Report, with exceptions or enhancements:

- BWR CRD Return Line Nozzle (B.2.1.6)
- BWR Vessel Internals (B.2.1.9)
- Bolting Integrity (B.2.1.11)
- Open-Cycle Cooling Water System (B.2.1.12)
- Closed Treated Water Systems (B.2.1.13)
- Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems (B.2.1.14)
- Fire Protection (B.2.1.17)
- Fire Water System (B.2.1.18)
- Aboveground Metallic Tanks (B.2.1.19)
- Fuel Oil Chemistry (B.2.1.20)
- Monitoring of Neutron-Absorbing Materials Other than Boraflex (B.2.1.28)
- Buried and Underground Piping and Tanks (B.2.1.29)
- ASME Code Section XI, Subsection IWE (B.2.1.30)
- ASME Code Section XI, Subsection IWL (B.2.1.31)
- ASME Code Section XI, Subsection IWF (B.2.1.32)
- Masonry Walls (B.2.1.34)
- Structures Monitoring (B.2.1.35)
- RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" (B.2.1.36)
- Protective Coating Monitoring and Maintenance Program (B.2.1.37)
- Fatigue Monitoring (B.3.1.1)

For AMPs that the applicant claimed are consistent with the GALL Report, with enhancements, the staff performed an audit and review to confirm that those attributes or features of the program, for which the applicant claimed consistency with the GALL Report, are indeed consistent. The staff reviewed the enhancements to determine if they will make the AMP consistent with the GALL Report AMP to which it is compared. The results of the staff's audits and reviews are documented in the following sections.

3.0.3.2.1 BWR Control Rod Drive Return Line Nozzle

<u>Summary of Technical Information in the Application</u>. LRA Section B.2.1.6 describes the existing BWR CRD Return Line Nozzle program as consistent, with an enhancement, with GALL Report AMP XI.M6, "BWR Control Rod Drive Return Line Nozzle."
The LRA states that the AMP addresses the control rod drive return line (CRDRL) nozzle exposed to reactor coolant to manage the effects of cracking. The LRA also states that the AMP proposes to manage this aging effect through ISI examinations, which include volumetric ultrasonic test examination of the CRDRL nozzles.

The applicant stated that modifications were implemented on LGS Units 1 and 2 based on recommendations in NUREG-0619, "BWR Feedwater Nozzle and Control Rod Drive Return Line Nozzle Cracking," to mitigate cracking because of thermal fatigue, in which the CRDRL nozzle was capped and the CRD return line to the reactor vessel was removed as part of the original plant design. Therefore, augmented inspections recommended by NUREG-0619 are not applicable.

Staff Evaluation. During its audit, 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.M6.

The staff reviewed NUREG-0991, "Safety-Report Related to the Operation of Limerick Generating Station, Units 1 and 2," and confirmed that the modifications to the CRDRL nozzle were reviewed and approved by the staff during initial licensing, which is consistent with the recommendations of NUREG-0619. By letter dated September 2, 1982, Philadelphia Electric Company submitted a description for the implementation of NUREG-0619 for LGS Units 1 and 2 that included the elimination of the return line and RPV nozzle from the design of the CRD system.

In addition, in response to modifications to the control rod system described in NUREG-0619, Philadelphia Electric Company stated, in the aforementioned letter, that equalizing valves are included between the cooling water header and the normal drive movement header, the normal drive movement exhaust water header is a stainless steel line and, as such, flush ports are not required, and the flow stabilizer loop is stainless steel, which is routed directly into the cooling water header. As described in Section 4.6 of NUREG-0991, "Safety Evaluation Report related to the operation of Limerick Generating Station Units 1 and 2," the applicant's configuration of the CRD system meets the guidelines in NUREG-0619.

The staff noted that the recommendations of GALL Report AMP XI.M6 for inspection of the CRDRL nozzle-to-cap weld are provided in ASME Code, Section XI, Table IWB-2500-1. However, LRA Section B.2.1.6 states that the CRDRL nozzle-to-cap weld examinations are performed at a frequency specified in its BWR Stress Corrosion Cracking program that implements commitments from GL 88-01 and BWRVIP-75-A.

In the final safety evaluation of BWRVIP-75, dated May 14, 2002, the staff concluded that the revised BWRVIP-75 guidance is acceptable for applicant referencing as the technical basis for relief from, or as an alternative to, the ASME Code Section XI and 10 CFR 50.55a requirements, in order to use the sample schedules and frequencies specified in the revised BWRVIP-75 report that are less than those that ASME Code, Section XI, requires.

The staff finds it acceptable that the applicant credits its BWR Stress Corrosion Cracking program and BWRVIP-75-A to manage cracking of the CRD nozzle-to-cap weld because the applicant is required to apply for relief from the ASME Code Section XI and 10 CFR 50.55a in accordance with 10 CFR 50.55a(a)(3). The staff has approved the technical basis in BWRVIP-75-A and the use of the sample schedules and frequencies specified in this report, which are less than those that the ASME Code requires. During its audit, the staff confirmed that unless the applicant receives relief in accordance with 10 CFR 50.55a(a)(3), the inspections of the CRD inner radius, nozzle-to-vessel weld and nozzle-to-cap weld will be performed in accordance with ASME Code, Section XI, Table IWB-2500-1, consistent with GALL Report AMP XI.M6.

The staff also reviewed the portions of the "detection of aging effects" program element associated with the enhancement to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B.2.1.6 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant states that the program will specify an extended volumetric inspection of the nozzle-to-cap weld to ensure 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, before the period of extended operation.

The "detection of aging effects" program element of GALL Report AMP XI.M6 states that the inspection is to include base metal to a distance of one pipe wall thickness or 0.5 inches, whichever is greater, on both sides of the weld.

The staff reviewed Section 8.2 of NUREG-0619 and noted that the plant-specific requirement for an extended volumetric inspection that includes the base metal to a distance of one pipe wall thickness or 0.5 inches, whichever is greater, on both sides of the weld, is only applicable to those licensees that have cut and capped the CRDRL nozzle with rerouting of the CRDRL. As described above, and in NUREG-0991, the applicant cut and capped the CRDRL nozzle and did not reroute the CRDRL; therefore, this requirement was not applicable to the applicant for its CLB. The staff noted that the inspections specified in ASME Code, Section XI, Table IWB-2500-1, are required by the applicant for the CLB for the CRDRL nozzle and associated welds.

The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M6 and finds it acceptable because when it is implemented, the applicant will be performing its volumetric inspection of the nozzle-to-cap weld consistent with the recommendations of GALL Report AMP XI.M6 and NUREG-0619. This will include base metal to a distance of one pipe wall thickness or 0.5 inches, whichever is greater, on both sides of the weld. In addition, when the applicant's program is enhanced before the period of extended operation, the inspections of the nozzle-to-cap weld will be beyond the recommendations specified in NUREG-0619 for licensees that cut and capped the CRDRL nozzle without rerouting the CRDRL.

Based on its audit of the BWR CRD Return Line Nozzle program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M6. In addition, the staff reviewed the enhancement associated with the "detection of aging effects" program element and finds that when implemented it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.6 summarizes operating experience related to the BWR CRD Return Line Nozzle program. The staff noted that a crack was identified in the LGS Unit 1 recirculation inlet nozzle-to-safe end weld in the Alloy 182 to Alloy 82 weld interface in the 1988 refueling outage. The applicant identified that the LGS Unit 1 CRDRL nozzle also has Alloy 182 to Alloy 82 weld interface between the nozzle and the cap; therefore, it performed MSIP on the nozzle-to-cap weld on the LGS Unit 1 CRDRL nozzle in 1994. In addition, since LGS Unit 2 was not in operation at the time, the CRDRL nozzle was modified to eliminate the Alloy 182 to Alloy 82 weld interfaces in contact with the reactor coolant by adding an Alloy 82 overlay over the Alloy 182 to Alloy 82 weld between the nozzle and cap. The staff noted that this resulted in the Alloy 182 to Alloy 82 dissimilar weld not being in contact with reactor coolant, thereby minimizing the probability of cracking in the nozzle-to-cap weld.

During its audit, the staff reviewed the applicant's results for LGSUnit 1 from 1992, 1998, and 2008, and for LGS, Unit 2 from 1995 and 2005. The staff confirmed that the inspections were performed in accordance with ASME Code Section XI, Table IWB-2500-1, and that there were no recordable indications for the CRD inner radius, nozzle-to-vessel weld, and nozzle-to-cap weld.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.6 provides the UFSAR supplement for the BWR CRD Return Line Nozzle program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 6) to enhance the existing BWR CRD Return Line Nozzle program to specify an extended volumetric inspection of the nozzle-to-cap weld to ensure 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 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 BWR CRD Return Line Nozzle program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR contained Commitment No. 6 to implement the enhancement before the period of extended operation. 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).

3.0.3.2.2 BWR Vessel Internals

Summary of Technical Information in the Application. LRA Section B.2.1.9 describes the existing BWR Vessel Internals program as consistent, with enhancements, with GALL Report AMP XI.M9, "BWR Vessel Internals." The applicant stated that this program includes inspection, flaw evaluation, and repair guidelines consistent with the guidelines addressed in relevant BWRVIP reports. The applicant further stated that water chemistry guidelines per the Water Chemistry program, B.2.1.2, will help to ensure the integrity of the RVIs components.

The BWR Vessel Internals program is an existing program that is consistent with AMP XI.M9, "BWR Vessel Internals," as specified in the GALL Report. No exceptions are taken by the applicant; there are three enhancements. The first two enhancements affect the program scope, in which the applicant states that it will perform assessments of CASS components for susceptibility to thermal and neutron embrittlement. The third enhancement is related to the parameters monitored and detection of the aging effect in which the applicant specifies the inspection methods and schedule for those CASS components identified in the first two enhancements.

The applicant provided information on plant operating experience in which it stated that inspections were performed on core shroud, core plate, shroud support, low-pressure coolant injection (LPCI) coupling, CS, jet pumps, top guide, CRD housings, lower plenum, steam dryer, and access hole covers. The applicant further stated that it evaluated the indications found so far in these reactor vessel internal components and accepted them based on the applicable BWRVIP inspection guidelines. The applicant reiterated that it complied with the inspections and flaw evaluation guidelines specified in the applicable BWRVIP reports. Further, it would continue to implement these guidelines to ensure the structural integrity and functionality of these components during the extended period of operation.

In the applicant's February 15, 2012, response to RAI BWRVIP-1, the applicant added Appendix C, which lists the following BWRVIP reports that would be implemented by the applicant's AMP and have action items for license renewal:

- BWRVIP-18, "BWR Core Spray Internals Inspection and Flaw Evaluation Guidelines (Revision 1)"
- BWRVIP-25, "BWR Core Plate Inspection and Flaw Evaluation Guidelines"
- BWRVIP-26-A, "BWR Top Guide Inspection and Flaw Evaluation Guidelines"
- BWRVIP-38, "BWR Shroud Support Inspection and Flaw Evaluation Guidelines"
- BWRVIP-41, "BWR Jet Pump Assembly Inspection and Flaw Evaluation Guidelines (Revision 2)"
- BWRVIP-42-A, "BWR LPCI Coupling Inspection and Flaw Evaluation Guidelines"
- BWRVIP-47-A, "BWR Lower Plenum Inspection and Flaw Evaluation Guidelines"
- BWRVIP-48-A, "BWR Vessel ID Attachment Weld Inspection and Flaw Evaluation Guidelines"
- BWRVIP-49-A, "BWR Instrument Penetration Inspection and Flaw Evaluation Guidelines"

- BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines for License Renewal"
- BWRVIP-76-A, "BWR Core Shroud Inspection and Flaw Evaluation Guidelines"

In Appendix C, the applicant included three license renewal action items applicable to all BWRVIP reports and several other license renewal action items applicable to specific BWRVIP reports. In addition, Appendix C addresses the applicant's response to the license renewal action items. The staff included the license renewal action items, the applicant's response, and its evaluation in the staff evaluation section for this AMP.

Staff Evaluation. During the audit, the staff reviewed the LRA Section B.2.1.9 and compared program elements 1-6 of the applicant's program to the corresponding program elements of GALL Report AMP XI.M9. The applicant routinely inspected the reactor vessel internal components per the applicable BWRVIP reports, and repaired or evaluated the indications per the BWRVIP reports or ASME Code, Section XI requirements. The staff noted that the applicant's program relies on monitoring and control of reactor water chemistry based on the guidance of BWRVIP-190 report (EPRI-1016579). Furthermore, the applicant has noted (AMR item 3.1.1-99) that there are no martensitic stainless steels, such as 17-4, 15-5, or 410, included in the reactor vessel internal components.

During the audit, the staff also reviewed the portions of the "scope of program" and "parameters monitored or inspected" program elements associated with enhancements to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.9 states an enhancement to the "scope of program" element. In this enhancement, the applicant will evaluate CASS materials used for the reactor vessel internal components to assess the loss of fracture toughness for the material because of thermal embrittlement. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M9 and finds it acceptable because when it is implemented, it will have reviewed the certified material test record (CMRT) for each CASS component. If the applicant cannot demonstrate the component's lack of susceptibility to thermal embrittlement or if the CMRT is not available, the component will be considered susceptible to thermal embrittlement.

Enhancement 2. LRA Section B.2.1.9 states an enhancement to the "scope of program" element. In this enhancement, the applicant will evaluate CASS materials used for the reactor internal components to assess the loss of fracture toughness for the material because of neutron embrittlement. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M9 and finds it acceptable because when it is implemented, it will have reviewed each CASS component and the neutron exposure of the component for the period of extended operation.

Enhancement 3. LRA Section B.2.1.9 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that either before entering the period of extended operation or within 5 years of entering the period of extended operation, the applicant will have inspected all reactor vessel internal components susceptible to either thermal or neutron embrittlement. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M9 and finds it acceptable because when it is implemented, it will ensure that all susceptible CASS components will be inspected for evidence of any subcritical cracking that could cause failure because of the loss of the material's fracture toughness caused by thermal or neutron embrittlement.

License Renewal Action Items Addressed in Appendix C. The LRA references several BWRVIP reports, which have been reviewed and approved by the staff, as part of its AMPs for the reactor vessel and its internal components. As part of the staff's approval of these BWRVIP reports, the staff's safety evaluations (SEs) on the reports included a number of AAIs that were to be addressed as part of the basis for applying the reports to the CLB. BWR applicants applying for license renewal of their facilities were requested to include their responses to the AAIs in their LRAs.

The applicant provided the following responses to three AAIs listed in the staff's SEs for all of the BWRVIP reports listed in response to RAI BWRVIP-1.

(1) LGS's AMPs for the reactor vessel internal components are bounded by the aforementioned BWRVIP reports.

(2) The UFSAR supplement addresses a summary of the programs and activities specified in the applicable BWRVIP reports.

(3) LGS states that no technical specification changes have been identified as a result of implementing the AMP for the reactor vessel internal components.

The staff reviewed the applicant's disposition for these three AAIs and concludes that the applicant complied with the intent of the license renewal action items the staff specified in its SEs for the applicable BWRVIP reports.

In addition to the three AAIs common to each BWRVIP report listed in the applicant's RAI response, the applicant provided responses to the following BWRVIP AAIs:

- BWRVIP-18, AAI No. 4
- BWRVIP-25, AAI Nos. 4 and 5
- BWRVIP-26-A, AAI No. 4
- BWRVIP-42-A, AAI Nos. 4 and 5
- BWRVIP-47-A, AAI No. 4
- BWRVIP-74-A, AAI Nos. 4 through 14
- BWRVIP-76-A, AAI Nos. 4 through 8

Several of the aforementioned AAI relate to TLAAs and are discussed in SER Section 4.1.2.1.2. These AAI are:

- BWRVIP-18, AAI No. 4
- BWRVIP-25, AAI No. 4
- BWRVIP-26-A, AAI No. 4
- BWRVIP-42-A, AAI No. 4
- BWRVIP-47-A, AAI No. 4
- BWRVIP-74-A, AAI Nos. 8 through 13

The following is the staff's evaluation of the remainder of the BWRVIP related AAIs for license renewal.

BWRVIP-25, AAI No. 5 states that "until such time as an expanded technical basis for not inspecting the rim hold-down bolts is approved by the staff, applicants referencing the BWRVIP-25 report for license renewal should continue to perform inspection of the rim hold-down bolts."

The applicant's' response to BWRVIP-25, AAI No. 5, states that inspection of the core plate rim hold-down bolts will be in compliance with BWRVIP guidance before and through the period of extended operation. The staff reviewed the applicant's response and found it acceptable because the applicant agrees to inspect the core plate rim hold down bolts in accordance with BWRVIP guidance before and through the period of extended operation.

BWRVIP-42-A, AAI No. 5, states that "the BWRVIP committed to address development of the technology to inspect inaccessible welds and to have the individual LR [license renewal] applicant notify the NRC of actions planned. Applicant's referencing BWRVIP-42 report for license renewal should identify the action as open and to be addressed once the BWRVIP's response to this issue has been reviewed and accepted by the staff."

The applicant's response to BWRVIP-42-A, AAI No. 5, states that inspection of the LPCI coupling is performed in accordance with BWRVIP guidelines and that there are no inaccessible welds associated with the LPCI couplings. The staff reviewed the applicant's response and found it acceptable because the applicant states that there are no inaccessible welds associated with the LPCI couplings.

The license renewal action items specified in the staff's SE for the BWRVIP-74-A report, dated October 18, 2001, address the aging effects on the reactor vessel components. This report also provides requirements to effectively manage the aging effects during the extended period of operation. The BWRVIP-74-A report addresses the license renewal action items associated with TLAAs for the extended period of operation. The following paragraphs address the TLAAs and the AMP related to reactor vessel components specified in the BWRVIP-74-A report, the applicant's responses to these license renewal action items, and the corresponding staff's evaluation of each item.

BWRVIP-74-A, AAI No. 4, states that an AMP should be identified for the vessel flange leak detector (VFLD) nozzle and piping. Cracking of the nozzle is managed by the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, and Water Chemistry programs. The applicant stated that it would manage cracking in the piping with the One-Time Inspection of ASME Code Class 1, Small-Bore Piping, Water Chemistry, and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs. The staff finds the applicant's AMP acceptable for the VFLD nozzle and piping because the combination of One-Time Inspection of ASME Code Class 1, Small-Bore Piping and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs will adequately identify the aging degradation in a timely manner and controlling water chemistry will enable the applicant to effectively manage the occurrence of any cracking or loss of material in VFLD nozzle and piping.

BWRVIP-74-A, AAI No. 5, states that the applicant should describe how each plant-specific AMP addresses the 10 elements listed in GALL Report AMP XI.M9. The applicant's response stated that there are no plant-specific AMPs credited for managing aging of RPV components and that descriptions of the AMPs credited for managing RPV components are described in

Appendix B of the LRA. The staff reviewed Appendix B and finds the applicant's response acceptable because Appendix B adequately addresses the 10 elements of the GALL Report AMP.

BWRVIP-74-A, AAI No. 6, recommends that the applicant include a water chemistry program in its LRA to ensure that it can effectively manage IGSCC in the RCS systems. In its response, the applicant stated that it would comply with the BWRVIP-190 report, which superseded the BWRVIP-29 report. The staff finds this response acceptable because the applicant's compliance with the requirements of BWRVIP-190 provides adequate mitigation to the occurrence of IGSCC.

BWRVIP-74-A, AAI No. 7 recommends that the applicant identify its RPV surveillance program. The applicant stated that it has implemented the staff-approved BWRVIP ISP, BWRVIP-86-A, "BWR Vessel and Internals Project BWR Integrated Surveillance Program Implementation Plan," for the current license period and BWRVIP-116, "BWR Vessel and Internals Project Integrated Surveillance Program" for the period of extended operation. Compliance with the staff-approved ISPs enables the applicant to effectively monitor neutron embrittlement of the RPV materials; therefore, the staff finds this response acceptable.

BWRVIP-74-A, AAI No. 14, recommends that components that have indications previously evaluated analytically, in accordance with Subsection IWB-3600 of the ASME Code, Section XI, until the end of the 40-year service period, shall be re-evaluated for the 60-year service period corresponding to the license renewal term. The applicant stated that a flaw was discovered in the LGS Unit 1 RPV nozzle to safe-end weld VRR-IRD-1A-N2H that was evaluated in accordance with ASME Code Section XI, Subsection IWB-3600. The UFSAR supplement contains a commitment (Commitment No. 47) to re-evaluate this condition before the period of extended operation. Furthermore, the applicant states that any subsequent flaw evaluations performed on other RPV components will be evaluated for the period of extended operation. The staff finds this response acceptable because the effects of aging on the intended function of the nozzle to safe-end weld will be adequately managed for the period of extended operation.

BWRVIP-76-A, AAI No. 4, recommends applicants incorporate BWRVIP-14-A, BWRVIP-99-A, and BWRVIP-100-A report-specific crack growth rate evaluations and fracture toughness values for cracked core shroud welds exposed to neutron fluence values specified in the relevant reports. The applicant also should confirm that any emerging inspection guidelines developed by the BWRVIP for these welds will be incorporated. The applicant's response includes the specific wording for AAI No. 4 to use current NRC-approved BWRVIP guidance for core shroud weld flaw evaluations and to incorporate any new approved guidance as it becomes available. Compliance with the staff-approved BWRVIP reports enables the applicant to effectively monitor crack growth in the core shroud welds; therefore, the staff finds the applicant's response acceptable.

BWRVIP-76-A, No. AAI 5 states that license renewal applicants that have core shrods with tie rod repairs shall make a statement in its program associated with reactor vessel internal components that they have evaluated the implications of the Hatch Unit 1 tie rod repair cracking on its units and incorporate revised inspection guidelines, if any, developed by the BWRVIP. The staff reviewed the applicant's response to BWRVIP-76-A, AAI No. 5 and finds it acceptable because the applicant states that there are no tie rod repairs in the core shrouds for LGS Units 1 and 2.

BWRVIP-76-A, AAI No. 6, recommends that the applicant identify the aging effects for the core shrouds and core shroud assembly components if a repair design modification has been implemented, and identify the specific AMPs or TLAAs that will be used to manage these effects for the period of extended operation. The applicant has responded that the core shrouds at LGS Units 1 and 2 are made from stainless steel and nickel alloy that are susceptible to cracking, loss of material because of pitting and crevice corrosion, and cumulative fatigue damage. No core shroud repairs have been done as stated in the response to AAI No. 5. The BWR Vessel Internals and Water Chemistry AMPs will be used to manage loss of material because of pitting and crevice corrosion during the period of extended operation. The staff has reviewed the applicant's AMR for item 3.1.1-43 and finds the applicant's aging management plan acceptable because it follows the guidelines recommended by the BWRVIP, which are often more stringent than those inspections specified by ASME Code Section XI, and include specific flaw evaluation and repair recommendations to facilitate post-inspection review; and the applicant's use of the Water Chemistry program creates an environment not conducive for loss of material to occur and is consistent with the recommendations of the GALL Report. LRA Section 4.3.4 discusses the applicant's TLAA for cumulative fatigue damage. The staff evaluated the TLAA associated with the core shroud cumulative fatigue damage for LGS Units 1 and 2 in SER Section 4.3.4.

BWRVIP-76-A, AAI No. 7 recommends that the applicant identify any core shroud or core shroud repair assembly components manufactured from materials other than stainless steel or nickel alloy and any aging effects that will require management for the period of extended operation. The applicant has responded that all of the materials in the core shroud and core shroud repair assembly components are made from stainless steel or nickel alloy. Therefore, no additional aging effects need to be addressed. The staff reviewed the applicant's response to AAI No. 7 in BWRVIP-76-A and finds it acceptable because the applicant states that there are no other materials included in the core shroud and core shroud repair assembly components at LGS Units 1 and 2.

BWRVIP-76-A, AAI No. 8 recommends that the applicant reference the staff-approved topical reports, BWRVIP-99 and BWRVIP-100-A, in its BWR Vessels Internals program. The applicant responded that the BWR Vessels Internals program at LGS Units 1 and 2 use BWRVIP-14-A and BWRVIP-99-A for crack growth rates and BWRVIP-100-A for fracture toughness values. The staff reviewed the applicant's response to AAI No. 7 in BWRVIP-76-A and finds it acceptable because the applicant states that its AMPs implement the BWRVIP-76-A requirements.

Based on its audit of the BWR Vessel Internals program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M9. In addition, the staff reviewed the enhancements associated with the "scope of program" and "parameters monitored or inspected" program elements and finds that when implemented the enhancements will make the AMP adequate to manage the applicable aging effects.

Operating Experience. The staff reviewed the applicant's "operating experience" program element discussions in the BWR Vessel Internals program and in the license renewal basis document for this program. The staff noted that the applicant has identified relevant plant-specific operating experience in the "operating experience" program element discussion for the BWR Vessels Internals program. Flaw indications have been found in the core shroud welds, CS spargers, steam dryer, and some of the jet pump assembly components (i.e., jet pump yoke to riser pipe weld, hold-down beam, and set screw tack welds). Wear on the slip joint clamp and set screw gaps was documented through video of the visual inspections. The staff also observed that the applicant has dispositioned the core shroud welds, steam dryer, and CS sparger weld flaw indications as acceptable (i.e., "as-is") for further service without the need for repair or replacement of the components at this time. Auxiliary wedges and slip joint clamps were installed to stabilize the location against future crack growth and replace the function of the set screw.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.1.2.9 provides the UFSAR supplement summary for the BWR Vessel Internals program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the UFSAR supplement also contains a commitment (Commitment No. 9) to enhance the existing BWR Vessel Internals program to: (1) evaluate CASS materials used for the reactor vessel internal components to assess the loss of fracture toughness for the material because of thermal embrittlement, (2) evaluate CASS materials used for the reactor internal components to assess the loss of fracture toughness for the material because of neutron embrittlement, and (3) inspect all reactor vessel internal components susceptible to either thermal or neutron embrittlement either before entering the period of extended operation or within 5 years of entering 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 BWR Vessel Internals program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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 contained Commitment No. 9 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.3 Bolting Integrity

Summary of Technical Information in the Application. LRA Section B.2.1.11 describes the existing Bolting Integrity program as consistent, with enhancements, with GALL Report AMP XI.M18, "Bolting Integrity." The LRA states that the program includes management of loss of material and loss of preload for pressure-retaining bolted joints by performing visual inspections for leakage. The LRA also states that the program includes preventive measures to ensure only approved lubricants and sealants and proper torque are applied. The program incorporates NRC and industry recommendations delineated in NUREG-1339, "Resolution of Generic Safety Issue 29: Bolting Degradation or Failure in Nuclear Power Plants," EPRI TR-104213, "Bolted Joint Maintenance and Applications Guide," and EPRI NP-5769, "Degradation and Failure of Bolting in Nuclear Power Plants."

Staff Evaluation. During its audit, 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.M18. For the "preventive actions" and "parameters monitored or inspected" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

GALL Report AMP XI.M18 recommends that the program include periodic inspections of closure bolting for loss of material, loss of preload, and cracking, as well as preventive measures to minimize loss of preload and cracking. The "preventive actions" program element of GALL Report AMP XI.M18 recommends that the preventive measures to minimize cracking include not using lubricants that contain MoS_2 and not using high-strength bolting materials. LRA Section B.2.1.11 states that high-strength bolts are not used on pressure-retaining bolted joints within the scope of the program and that station procedures ensure that lubricants containing MoS_2 are not used. However, the program does not state that it manages cracking and does not include inspections for cracking. By letter dated January 17, 2012, the staff issued RAI B.2.1.11-1 requesting the applicant to clarify if cracking is an aging effect being managed by the Bolting Integrity program and either revise the LRA description of the program and the UFSAR supplement to include management of cracking or justify the exception to the GALL Report AMP.

In its response, dated February 15, 2012, the applicant stated that cracking is an aging effect managed by the Bolting Integrity program. The applicant revised the LRA to state that the program manages cracking and that safety-related pressure-retaining bolting that is not high strength is visually inspected for leakage, loss of material, cracking, and loss of preload at least once per refueling cycle. The applicant also stated that high-strength bolting, if used, will be monitored for cracking. The applicant further stated that other pressure-retaining bolting is inspected for leakage that could result from cracking. The staff finds the applicant's response acceptable because the program has been revised to include periodic inspections of pressure-retaining bolting for cracking, consistent with the GALL Report recommendations.

The "parameters monitored or inspected" program element of GALL Report AMP XI.M18, states that bolting for safety-related pressure-retaining components should be inspected for leakage as well as loss of material, cracking, and loss of preload. LRA Section B.2.1.11 states that the program will manage loss of material and loss of preload using visual inspections for pressure-retaining bolted joint leakage. The LRA does not state that inspections will be performed for other indications of loss of material (such as corrosion or rust), cracking, or loss of preload (such as loose or missing bolts). By letter dated January 17, 2012, the staff issued RAI B.2.1.11-2 requesting the applicant to clarify if the inspections performed by the Bolting Integrity program include inspections for other indications of loss of material, cracking, and loss of preload and either revise the LRA description of the program and the UFSAR supplement to include this information or justify the exception to the GALL Report AMP.

In its response, dated February 15, 2012, the applicant stated that safety-related pressure-retaining bolting is visually inspected for leakage, loss of material, cracking, and loss of preload at least once per refueling cycle. The applicant also stated that other pressure-retaining bolting is inspected for leakage. The staff finds the applicant's response acceptable because the program has been revised to include periodic inspections of safety-related pressure-retaining bolting for loss of material, cracking, and loss of preload, consistent with the GALL Report recommendations.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" program elements associated with the 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.

Enhancement 1. LRA Section B.2.1.11 states an enhancement to the "preventive actions," "detection of aging effects," and "corrective actions" program elements. In this enhancement, the LRA states that guidance will be provided to ensure proper specification of bolting material, lubricants and sealants, storage, and installation torque or tension to prevent or mitigate degradation or failure of closure bolting. GALL Report AMP XI.M18 states that selection of bolting materials, lubricants, and sealants should be in accordance with EPRI NP-5769 and NUREG-1339, and that maintenance practices should include application of proper preload based on EPRI documents, manufacturer recommendations, or engineering evaluations. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP by ensuring that proper specifications are used.

Enhancement 2. LRA Section B.2.1.11 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that it will prohibit the use of lubricants containing MoS_2 for closure bolting. GALL Report AMP XI.M18 states that lubricants containing MoS_2 have been shown to contribute to SCC and should not be used. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP.

Enhancement 3. LRA Section B.2.1.11 states an enhancement to the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the applicant stated that it will minimize the use of high-strength closure bolting, and, if used, it will be monitored for cracking. GALL Report AMP XI.M18 states that bolting material should be limited to an actual measured yield strength of 1,034 MPa (150 ksi) and high-strength closure bolting (with yield strength greater than 1,034 MPa or 150 ksi) should be monitored for cracking if used. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP.

Enhancement 4. By letter dated March 13, 2012, the applicant amended LRA Section B.2.1.11 to add 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 visual inspections of submerged bolting for the RHR system, CS system, HPCI system, and RCIC system suction strainers in the suppression pool for loss of material and loss of preload during each ISI inspection interval. GALL Report AMP XI.M18 states that the program manages aging of closure bolting for pressure-retaining components within the scope of license renewal for aging effects, including loss of material and loss of preload. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M18 and finds it acceptable because when it is implemented, the visual inspections for loss of material and loss of preload will make the program consistent with the recommendations in the GALL Report AMP.

Based on its audit and review of the applicant's responses to RAIs B.2.1.11-1 and B.2.1.11-2, 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 GALL Report AMP XI.M18. In addition, the staff reviewed the enhancements associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "corrective actions" program elements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.11 summarizes operating experience related to the Bolting Integrity program. In one operating experience example, the LRA states that an inspection identified a loose bolt on the EDG oil cooler discharge flange. An operability evaluation was performed and the loose bolt was subsequently re-tightened as required by design. In another operating experience example, the LRA states that one displaced nut and one loose nut were identified during disassembly of the reactor feed pump suction flange. The loose nuts were attributed to incorrect use of a torque wrench during a previous outage. A maintenance history review identified that another flange was disassembled during the previous outage. As a result, that flange was inspected to ensure proper torque was applied and it was found to be in acceptable condition.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.11 provides the UFSAR supplement for the Bolting Integrity program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR contains a commitment (Commitment No. 11), as amended by letter, dated March 13, 2012, to enhance the program before the period of extended operation to provide guidance to ensure proper specification of bolting material, lubricants and sealants, storage, installation torque or tension; to prohibit the use of lubricants containing MoS_2; and to minimize the use of high-strength closure bolting, and, if used, monitor the high-strength bolting for cracking and perform visual inspection of bolting for the RHR, CS system, HPCI system, and RCIC system suppression pool suction strainers for loss of material and loss of preload during each ISI inspection interval. The staff finds the information in the UFSAR supplement, as amended by letter, dated March 13, 2012, is an adequate summary description of the program. Conclusion. On the basis of its audit and review of the Bolting Integrity 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 GALL Report AMP XI.M18. 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. 11 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.4 Open-Cycle Cooling Water System

Summary of Technical Information in the Application. LRA Section B.2.1.12 describes the existing Open-Cycle Cooling Water System program as consistent, with enhancements, with GALL Report AMP XI.M20, "Open-Cycle Cooling Water System." The LRA states that the program is consistent with the LGS commitments for GL 89-13, "Service Water Problems Affecting Safety-Related Components," and manages piping components and heat exchangers exposed to raw water for loss of material, reduction of heat transfer, and loss of elastomeric properties through tests, visual inspections, nondestructive examinations (NDEs), and cleaning activities. The LRA also states that the program includes chemical and biocide injections and performs periodic inspections for the presence of mollusks and biofouling. The LRA further states that heat transfer capabilities are confirmed through periodic heat transfer testing, or inspection and cleaning of heat exchangers, and that polymeric materials included in this program are examined consistent with those described in the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

Staff Evaluation. During its audit, 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.M20. The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements associated with the enhancements to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of these enhancements follows.

Enhancement 1. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected" and the "detection of aging effects" program elements. In this enhancement, the applicant stated that inspections of the internal surfaces of buried safety-related SW piping will be performed when it is accessible during maintenance and repair activities. It was not clear to the staff how opportunistic inspections of the buried safety-related service water piping will be capable of assessing its condition before loss of intended function occurs. By letter dated January 17, 2012, the staff issued RAI B.2.1.12-1 requesting, in part, the applicant to provide the technical bases to justify how opportunistic inspection will be capable of assessing the condition of buried safety-related SW piping before the loss of intended function.

In its response dated February 15, 2012, the applicant stated that the internal surface of the buried SW piping is subject to similar process conditions as the RHRSW piping in the pipe tunnel, and inspection results for piping in the pipe tunnel will be applied to the buried piping. The applicant also stated that replacement of degraded RHRSW piping in the pipe tunnel is planned between 2012 and 2015, and the removed piping will be extensively examined, including 100 percent visual examination and ultrasonic examination at locations determined by the visual inspections. The response further stated that during the pipe replacement, the buried piping will be drained and accessible for inspection and that this opportunistic inspection of the buried pipe, coupled with the detailed inspection of the similar pipe removed from the pipe tunnel, will provide information needed to assess the potential degradation of the buried piping. The applicant committed (Commitment No. 12) to inspect safety-related SW system piping at a minimum of 10 locations each refueling outage interval, which will result in 50 inspections in 10 years.

The staff finds the applicant's response acceptable because: the opportunistic inspection of the buried piping was clarified as at least occurring during the replacement of the RHRSW piping in the pipe tunnel between 2012 and 2015; the detailed inspections of the piping removed during the replacement will provide supplemental information to assess the condition of the buried piping; degradation of the piping in aboveground portions of the system will be consistent with the buried piping given similar operating conditions (see discussion of applicant's response in Enhancement 5); and the 50 inspections that will occur in each 10-year interval of the period of extended operation will provide sufficient timely data to allow the applicant to understand the condition of the internal surfaces of the buried piping. The staff's concern described in RAI B.2.1.12-1, which addressed Enhancement 1, is resolved. Other aspects of RAI B.2.1.12-1 are addressed below under "Operating Experience" and "UFSAR Supplement."

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because when it is implemented, it will manage buried safety-related SW piping, such that loss of material will be detected before loss of intended function. The staff noted that in its response to RAI B.2.1.12-3 dated June 22, 2012, discussed below in "UFSAR Supplement" the applicant revised LRA Sections A.2.1.12 and B.2.1.12 to perform ten volumetric inspections in the safety-related portions of the SW system every 2 years to provide a sufficient understanding of the buried SW piping conditions. This does not change the finding for the closure of the concerns related to RAI B.2.1.12-1 because the same number of inspections will be conducted every 10-year period.

Enhancement 2. LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected" and the "detection of aging effects" program elements. In this enhancement, the applicant stated that periodic inspections of nonsafety-related SW piping for loss of material will be performed at a frequency in accordance with GL 89-13. The staff noted that GL 89-13 does not specify inspection frequencies for loss of material and the applicant's responses to that GL did not provide specific inspection frequencies for loss of material. By letter dated January 17, 2012, the staff issued RAI B.2.1.12-2 requesting the applicant to describe the number, frequency, and locations of inspections for nonsafety-related SW system.

In its response dated February 15, 2012, the applicant revised LRA Sections A.2.1.12, B.2.1.12, and Appendix A.5 to state that the nonsafety-related SW system will be inspected at a minimum of five locations on each unit once every refueling cycle. In addition, the applicant stated that the specific locations for these inspections are determined based on susceptibility to aging effects to ensure that loss of material will be detected before loss of intended function. The staff finds the response acceptable because the applicant clarified the number, frequency, and locations of the inspections associated with this enhancement and revised the corresponding sections of the LRA. The staff's concern described in RAI B.2.1.12-2 is resolved. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because when it is implemented, this program will manage nonsafety-related SW piping, such that loss of material will be detected before loss of intended function.

Enhancement 3. As amended by letter dated February 15, 2012, LRA Section B.2.1.12 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that it will replace the supply and return piping for the CS pump compartment unit coolers with stainless steel piping before the period of extended operation. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M20 and finds it acceptable because when it is implemented, it will reduce the susceptibility to material loss caused by corrosion.

Enhancement 4. As amended by letter dated February 15, 2012, LRA Section B.2.1.12 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that it will replace degraded RHRSW piping in the pipe tunnel before the period of extended operation. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M20 and finds it acceptable because when it is implemented, it will reduce the susceptibility to material loss caused by corrosion.

Enhancement 5. As amended by letter dated June 22, 2012, LRA Section B.2.1.12 states an enhancement to the "parameters monitored or inspected" and the "detection of aging effects" program elements. In this enhancement, the applicant stated that it will perform periodic inspections for loss of material in the safety-related SW system at a minimum of ten locations every 2 years. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M20 and finds it acceptable because when it is implemented, it will provide sufficient timely data to allow the applicant to understand the condition of the internal surfaces of the buried piping in the SW system.

Based on its audit of the Open-Cycle Cooling Water System program, and review of the applicant's responses to RAI B.2.1.12-1 and RAI B.2.1.12-2, the staff finds the program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M20. The staff also reviewed the enhancements associated with the "parameters monitored or inspected" and the "detection of aging effects" program elements and finds that when implemented they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.12 summarizes operating experience related to the Open-Cycle Cooling Water System program. The LRA discussed the identification of three localized, thinned areas in the 30-inch cross-tie piping of the RHRSW system, which were found during the augmented inspections to address another flaw in the same system. The LRA stated that an evaluation of the thinned areas determined these locations met the criteria for operability, that re-inspections of these areas were performed on a 30-day interval until repairs could be made, and that additional locations were selected for augmented wall thickness measurements. The LRA also discussed a recent inspection of the spray pond and cooling towers, which, for the first time, identified a live clam in a sludge sample from the spray pond. The LRA stated that LGS applied a clam control chemical treatment to the spray pond and notified personnel involved in SW system heat exchanger inspections of this occurrence. The LRA stated that the above examples provided objective evidence that the Open-Cycle Cooling Water System program will be effective in ensuring that the intended functions are maintained consistent with the CLB during the period of extended operation.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff identified operating experience for which it determined the need for additional clarification.

As noted in the LRA's operating experience discussion for this program, multiple leaks have occurred in the ESW piping over the years. Documentation that the staff reviewed during the audit indicated that the historical corrosion issues in small and medium diameter piping have more recently become evident in the large diameter piping of the ESW and RHRSW systems. Based on the applicant's evaluations, although the current chemical treatment appears to be appropriate, no chemical treatment is capable of reaching the active corrosion cells under the deposits of corrosion products, silt, and tubercles. As such, the existing carbon steel piping will continue to degrade. However, the LRA did not provide information about corrective actions taken to prevent recurrence of the identified problem. By letter dated January 17, 2012, the staff issued RAI B.2.1.12-1 requesting, in part, that the applicant provide information about corrective actions being performed to identify loss of material before through-wall leakage occurs. Furthermore, if these corrective actions include plans for pipe replacement, the applicant was requested to provide those aspects that can be credited in license renewal to alleviate ongoing degradation. In addition, the RAI requested the applicant to provide summaries of structural integrity analyses for previous degradation, which demonstrate that multiple adjacent corrosion sites with a cumulative adverse impact will not occur during the period of extended operation.

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

- Its GL 89-13 inspections include nine representative locations that use ultrasonic testing at inspection frequencies ranging from 1.5 years to 8 years.
- It has performed more than 250 ultrasonic test inspections in the past 5 years based on visual inspection results, operating experience, guided wave inspections, and augmented inspections required by application of ASME Code Case N-513.
- It currently performs additional ultrasonic test inspections at 37 locations at frequencies ranging from 6 months to 15 years.
- It has implemented material improvements in the related systems that include replacement of more than 2,000 feet of carbon steel piping with stainless steel in systems for components, including the EDG heat exchanges, the HPCI room cooler, the RHR pump compartment unit coolers, the RHR pump motor oil coolers, and certain CS pump compartment unit coolers.
- It plans to complete the replacement, by 2015, of additional carbon steel piping with stainless steel in CS pump compartment unit coolers and the RHRSW piping located in the pipe tunnel.

- The structural integrity analyses for previously identified degradation have used the evaluation requirements of ASME Code Case N-513 and where pipe inspections identify multiple corrosion sites, they are evaluated using the criteria of ASME Code, Section XI, Article IWA-3000, to determine if they may be evaluated as separate flaws. The associated piping inspections consist of full circumferential ultrasonic thickness scans at least 3 inches on either side of the location of interest and the entire boundary of any thinned area is recorded even if it extends beyond the original examination area. The structural integrity evaluations include hoop, axial, vacuum and buckling wall thickness, and operability evaluations consider loss of flow, spray on adjacent components, flooding, and potential for flaw propagation.

In addition, the applicant revised LRA Sections A.2.1.12, B.2.1.12, and Appendix A.5 to state that the enhancement to the Open-Cycle Cooling Water System program includes replacement of the supply and return piping for the CS pump compartment unit coolers and the degraded RHRSW piping in the pipe tunnel. The staff finds the applicant's response acceptable because the extent of corrective actions taken and the planned enhancements before the period of extended operation will ensure that the system's functions will be maintained during the period of extended operation. In addition, the structural integrity analyses used the evaluation criteria and considered multiple adjacent corrosion sites in accordance with the ASME Code requirements. The staff's concern described in RAI B.2.1.12-1 is resolved.

Based on its audit, its review of the application, and its review of the applicant's responses to RAI B.2.1.12-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

<u>UFSAR Supplement</u>. LRA Section A.2.1.12, as modified in response to RAI B.2.1.12-1 and B.2.1.12-2, provides the UFSAR supplement for the Open-Cycle Cooling Water System program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1; however, in its response to RAI B.2.1.12-2, the applicant revised the UFSAR supplement and Commitment No. 12 to perform five inspections per unit per refueling outage interval in the nonsafety-related portions of the SW system. As documented above in the staff evaluation of Enhancement 1, the staff believes that these inspections, in conjunction with opportunistic inspections, are necessary to ensure that the buried portions of the SW system will meet its intended function(s) during the period of extended operation. However, the UFSAR supplement, as amended, does not establish this link. By letter dated June 21, 2012, the staff issued RAI B.2.1.12-3 requesting that the applicant revise the UFSAR supplement to make clear that the nonsafety-related inspections of the SW system are required to ensure the buried SW piping will meet its CLB function(s) during the period of extended operation.

In its response dated June 22, 2012, the applicant stated it will conduct ten inspections of safety-related nonburied piping every 2 years in locations with service conditions that are representative of the buried piping (e.g., flow, temperature) in order to provide a sufficient understanding of the buried SW piping conditions. The applicant revised LRA Sections A.2.1.12 and B.2.1.12 to reflect the quantity, periodicity, location criteria, and purpose of these inspections as they related to the condition of buried piping.

The staff finds the applicant's response acceptable because the 50 inspections that will occur in each 10-year interval of the period of extended operation will provide sufficient, timely data to allow the applicant to understand the condition of the internal surfaces of the buried piping and the applicant has revised the UFSAR supplement such that the licensing basis will reflect the quantity, periodicity, location criteria, and purpose of these inspections as they relate to the condition of buried piping.

The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 12) to enhance its Open-Cycle Cooling Water System program to perform internal inspections of buried safety-related SW piping when it is made accessible for maintenance, 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, replace the supply and return piping for the CS pump compartment unit coolers, replace the degraded RHRSW piping in the pipe tunnel before the period of extended operation, and perform periodic inspections for loss of material in the safety-related SW system at a minimum of ten locations every 2 years.

The staff finds that the information in the UFSAR supplement, as amended by letters dated February 15, 2012 and June 22, 2012, is an adequate summary of the program

Conclusion. On the basis of its audit and review of the Open-Cycle Cooling Water System program the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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. 12 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.5 Closed Treated Water Systems

Summary of Technical Information in the Application. LRA Section B.2.1.13 describes the existing Closed Treated Water Systems program as consistent, with an enhancement, with GALL Report AMP XI.M21A, "Closed Treated Water Systems." The LRA states that the AMP manages loss of material and reduction of heat transfer in piping, piping components, piping elements, tanks, and heat exchangers exposed to a closed treated water environment. The LRA also states that the program includes nitrite-based water treatment to modify the chemical composition of the water such that the effects of corrosion are minimized and chemical testing of the water to ensure that the water chemistry remains within acceptable guidelines.

Staff Evaluation. During its audit, 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.M21A.

For the "scope of program," "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "scope of program," "preventive actions," "parameters monitored or inspected," and "detection of aging effects" program elements in GALL Report AMP XI.M21A recommend that cracking caused by SCC to be managed by maintenance of water chemistry and periodic inspections. However, during its audit, the staff found that the Closed Treated Water Systems program does not manage cracking caused by SCC. By letter dated January 17, 2012, the staff issued RAI B.2.1.13-1 requesting the applicant to justify why cracking caused by SCC is not an AERM and to clarify whether the temperature of the closed cycle cooling water environment is above or below the SCC threshold of 60° C (140 °F).

In its response dated February 15, 2012, the applicant stated that SCC is not applicable because there are no stainless steel components in these systems exposed to a closed cycle cooling water environment that is greater than 60° C (140 °F). The applicant revised LRA Table 3.0-1 to clarify that the GALL Report environment of "closed-cycle cooling water greater than 60°C (140°F)" is not used.

The staff finds the applicant's response acceptable because it confirmed that the closed cycle cooling water environment is below the SCC temperature threshold defined in the GALL Report; therefore, SCC is not an AERM. The staff's concern described in RAI B.2.1.13-1 is resolved.

The staff also reviewed the portions of the "parameters monitored or inspected" and "detection of aging effects" program elements associated with an enhancement to determine if the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement 1. LRA Section B.2.1.13 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that 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. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because when it is implemented, it will be capable of ensuring the effectiveness of the water treatment and testing activities by detecting the presence or extent of corrosion before loss of intended functions.

Enhancement 2. In response to RAI B.2.1.13-2.1, which addressed plant-specific operating experience, the applicant provided an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this enhancement, the applicant stated that condition monitoring for loss of material because of cavitation erosion will be performed in the reactor enclosure cooling water piping to the RWCU nonregenerative heat exchanger, with an initial inspection frequency of 4 years and future frequency adjustments based on trend data. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M21A and finds it acceptable because when it is implemented,, it will be capable of managing loss of material before loss of intended function. Additional discussion about the identification and resolution of this issue is given below in "Operating Experience."

Based on its audit, and review of the applicant's responses to RAIs B.2.1.13-1 and B.2.1.13-2.1, of the Closed Treated Water System program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M21A. In addition, the staff reviewed the enhancements associated with the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.13-1 summarizes operating experience related to the Closed Treated Water Systems program. The applicant had no operating experience related to corrosion or cracking of components in the closed treated water systems. Examples of operating experience related to the maintenance of water chemistry are given below. In each case, the experience was related to the diagnosis of potentially adverse trends, rather than the water chemistry diverging from acceptable limits.

In January 2009, an increasing trend in the number of chemical additions required to maintain the LGS Unit 1 turbine enclosure cooling water system was noted. Decreasing levels of nitrite and tolyltriazole (TTA) were determined to be consistent with a leak in the system and troubleshooting of the leak was turned over to the system manager. In November 2007, nitrite and TTA levels were determined to be near the low end of the desired concentration range in the control enclosure chilled water system. The applicant had a concern that additions to raise the levels of the chemical components may unacceptably raise the potential of hydrogen (pH). Chemical addition strategies to raise the nitrite and TTA concentrations without exceeding pH goals were evaluated, which led to an issue report to document the condition and request a plan of action.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff identified operating experience for which it determined the need for additional clarification and resulted in the issuance of an RAI, as discussed below.

The operating experience discussion in LRA Section B.2.1.22, "One-Time Inspection," states that ultrasonic test examinations in 2007 confirmed ongoing loss of material from erosion because of cavitation in the supply piping of the reactor enclosure cooling water system to the RWCU nonregenerative heat exchanger. The LRA stated that periodic inspections were implemented to monitor the progression of this loss of material. The staff noted that LRA Table 3.3.2-2, "Closed Cooling Water System," manages loss of material because of general, pitting, galvanic, or crevice corrosion through the control of water chemistry in the Closed Treated Water Systems program, but there were no AMR items that managed loss of material from erosion caused by cavitation. By letter dated January 17, 2012, the staff issued RAI B.2.1.13-2 requesting the applicant to provide a description of the AMP it proposes to use to manage the loss of material caused by cavitation erosion, to provide the apparent cause of this degradation mechanism and a summary of the extent of condition establishing that this mechanism is not applicable to other components, and to explain why this degradation mechanism was not identified in the LRA.

In its response dated February 15, 2012, the applicant stated that this degradation mechanism will be managed by the Closed Treated Water Systems program, which is described in LRA Section B.2.1.13 and includes an enhancement for periodic condition monitoring using NDEs at an interval not to exceed 10 years. The applicant stated that it had established a recurring task to trend the erosion rate with an initial monitoring frequency of 4 years, and that the frequency would be adjusted once a trend has been established, but in no case would the inspection interval exceed 10 years during the period of extended operation. The applicant revised LRA Table 3.3.2-2, "Closed Cooling Water System," to include an item that cites a plant-specific note, stating that the Closed Treated Water Systems program has been enhanced to include periodic NDE to manage this degradation mechanism. The response also stated that the degradation occurs in an elbow located downstream of a normally throttled valve, that an extent of condition review did not identify other instances of cavitation erosion for any components within the scope of license renewal, and that this degradation mechanism was not included in the LRA because it was not considered an applicable aging effect for the period of extended operation.

In its review of the applicant's response, the staff noted that the existing enhancement included with this AMP stated that it included condition and performance monitoring "to verify the effectiveness of the water chemistry control at mitigating aging effects." The staff did not consider the existing enhancement as an adequate way to manage this degradation since water chemistry control will not address loss of material caused by cavitation erosion and the enhancement did not describe the 4-year inspection frequency or the adjustment to the frequency as discussed in the applicant's response. By letter dated April 5, 2012, the staff issued followup RAI B.2.1.13-2.1, requesting the applicant provide information for enhancements to the appropriate program elements, and to discuss any monitoring activities such as temperatures or flow rates, which may need to be trended to establish the cavitation erosion rate.

In its response dated April 13, 2012, the applicant clarified that the associated valve was replaced during maintenance activities in 2007, and that no further noise or vibration had been observed, which indicated that cavitation erosion was no longer occurring. The applicant also stated, however, that the condition monitoring activities discussed in its previous RAI response would remain in place to verify that the loss of material has been arrested, and the applicant provided an enhancement to the program with a corresponding revision to Commitment No. 13 to ensure implementation of these confirmation activities. The staff finds the applicant's response acceptable because plant-specific operating experience has resulted in appropriate program enhancements, and the ongoing monitoring activities to manage loss of material downstream of the valve ensure that aging effects are detected before there is a loss of component intended function(s). The staff's concerns described in RAIs B.2.1.13-2 and B.2.1.13-2.1 are resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAIs B.2.1.13-2 and B.2.1.13-2.1, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

<u>UFSAR Supplement</u>. LRA Section A.2.1.13, as amended in response to RAI B.2.1.13-2.1, provides the UFSAR supplement for the Closed Treated Water Systems program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 13, as modified in response to RAI B.2.1.13-2.1) to enhance the Closed Treated Water Systems program to include the inspection of a representative sample of piping and components at an interval not to exceed once in 10 years during the period of extended operation, and to perform condition monitoring inspections for loss of material in the reactor enclosure cooling water system at an initial frequency of 4 years.

The staff finds that the information in the UFSAR supplement, as amended by letter dated April 13, 2012, is an adequate summary description of the program.

Conclusion. On the basis of its audit and review of the Closed Treated Water Systems program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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. 13 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.6 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems

Summary of Technical Information in the Application. LRA Section B.2.1.14 describes the existing Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program as consistent, with enhancements, with GALL Report AMP XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems." The LRA states that the program manages loss of material for the bridge, bridge rails, bolting, and trolley structural components and loss of preload for the bolted connections exposed to indoor air or treated water. The program implements the guidance provided in NUREG-0612, "Control of Heavy Loads at Nuclear Power Plants." The LRA also states that the program includes periodic inspections that are consistent with the recommendations in the ASME B30 series of standards.

Staff Evaluation. During its audit, 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.M23. The staff also reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" 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.

Enhancement 1. LRA Section B.2.1.14 states an enhancement to the "scope of program" and "detection of aging effects" program elements. In this enhancement, the LRA states that annual periodic inspections will be performed as defined in the ASME B30 series of standards. The LRA also states that annual periodic inspections for handling systems that are infrequently in service may be deferred until just before use. GALL Report AMP XI.M23 recommends that crane rails and structural components be visually inspected for loss of material caused by corrosion and wear and that bolted connections be inspected for loss of preload at a frequency in accordance with the appropriate ASME B30 series standard. GALL Report AMP XI.M23 states that infrequently used systems, such as containment polar cranes, may be inspected once every refueling outage just before use. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because when it is implemented, it will incorporate the annual periodic inspection criteria from the ASME B30 series standards to make the program consistent with the inspection criteria and frequencies recommended in the GALL Report AMP.

Enhancement 2. LRA Section B.2.1.14 states an enhancement to the "scope of program," "parameters monitored or inspected," and "detection of aging effects" program elements. In this enhancement, the LRA states that inspections will be performed for loss of material caused by corrosion for structural components and bolting; loss of material caused by wear and corrosion for rails; and loss of preload for bolted connections. GALL Report AMP XI.M23 recommends that the bridge, bridge rails, and trolley structural components be visually inspected for loss of material caused by corrosion; rails to be visually inspected for loss of material caused by wear; and bolted connections to be inspected for signs of loss of preload. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because when it is implemented, it will make the program consistent with the GALL Report AMP.

Enhancement 3. LRA Section B.2.1.14 states an enhancement to the "acceptance criteria" program element. In this enhancement, the LRA states that loss of material caused by wear, loss of material caused by corrosion, and loss of preload will be evaluated in accordance with the appropriate ASME B30 series standard. GALL Report AMP XI.M23 recommends that any indication of loss of material or loss of preload be evaluated in accordance with the applicable ASME B30 series standard. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because when it is implemented, it will incorporate the evaluation criteria from the ASME B30 series standard to make the program consistent with the GALL Report AMP.

Enhancement 4. LRA Section B.2.1.14 states an enhancement to the "corrective actions" program element. In this enhancement, the LRA states that repairs to cranes, hoists, and equipment handling systems will be performed in accordance with the appropriate ASME B30 series standard. GALL Report AMP XI.M23 recommends that repairs be performed in accordance with the appropriate ASME B30 series standard. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M23 and finds it acceptable because when it is implemented, it will make the program consistent with the GALL Report AMP.

Based on its audit, and review of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M23. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," "acceptance criteria," and "corrective actions" program elements and finds that when implemented they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.14 summarizes operating experience related to the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program. In one operating experience example, the LRA states that wear was identified on the refueling platform trolley rail, which caused minor binding of the trolley during movement. The wear and binding was attributed to the trolley not being mounted in a plumb condition. The LRA also states that corrective actions were taken to repair trolley alignment and periodically clean and lubricate the trolley rails. During the audit, the staff reviewed this operating experience example and noted that wear readings have been steady since trolley alignment was repaired. In another operating experience example, the LRA states that inspection of the reactor enclosure overhead crane identified a potentially cracked bolt on the main hoist hook block. Corrective action was taken to further inspect the bolt. The further inspection identified that only the coating was degraded. As a result, the hook block was repainted.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.14 provides the UFSAR supplement for the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 14) to enhance the program before the period of extended operation to perform periodic annual inspections as defined in ASME B30 series standards except for infrequently used equipment, which will be inspected just before use; inspect structural components and bolting for loss of material caused by corrosion, rails for loss of material caused by wear, and bolting for loss of preload; evaluate loss of material or loss of preload in accordance with ASME B30 series standards; and perform repairs in accordance with ASME B30 series standards. 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 Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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. 14 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.7 Fire Protection

Summary of Technical Information in the Application. LRA Section B.2.1.17 describes the existing Fire Protection program as consistent, with enhancements, with GALL Report AMP XI.M26, "Fire Protection." The LRA states that the program includes visual inspections of fire barrier walls, ceilings, floors, fire dampers, and penetration seals; and visual inspections and functional testing of fire doors and the halon and carbon dioxide systems. The LRA also states that the inspections and functional tests are performed in accordance with guidance in the applicable National Fire Protection Association (NFPA) codes and standards.

Staff Evaluation. During its audit, 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.M26. For the "scope of program" and "detection of aging effects" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "scope of program" program element of GALL Report AMP XI.M26 states that the program includes visual inspections of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire-resistant materials that perform a fire barrier function. The LGS Units 1 and 2 UFSAR states that gypsum fire barrier walls, fiberglass sleeving fire barriers, and refractory material raceway fire stops covered with silicone rubber are used at the plant as fire barriers. However, the LRA does not include any aging management results for components constructed of these materials. By letter dated January 17, 2012, the staff issued RAI B.2.1.17-1 requesting the applicant to explain how the gypsum, fiberglass sleeving, and refractory material fire barriers discussed in the UFSAR are being managed for aging.

In its response, dated February 15, 2012, the applicant stated that gypsum, ceramic fiber, and refractory covered with silicone rubber materials are used as fire barriers at the site and were inadvertently omitted from the LRA. The applicant also stated that both the ceramic fiber and refractory materials are alumina silica products. The applicant revised LRA Table 3.3.2-9 to include AMR items for the gypsum and alumina silica fire barriers. The applicant further stated that the fiberglass sleeving is used as a fire barrier when RG 1.75 separation recommendations cannot be met. Fiberglass sleeving is not used as a fire barrier at the site and does not perform a license renewal intended function. The staff finds the applicant's response acceptable because the alumina silica and gypsum fire barriers have been added to the LRA to be managed for aging and the fiberglass sleeving does not require aging management because it has no license renewal intended function. Evaluation of aging management for the gypsum and alumina silica fire barriers is discussed in SER Section 3.3.2.3.9.

The "detection of aging effects" program element of GALL Report AMP XI.M26 recommends visual inspections be performed by fire protection qualified personnel of not less than 10 percent of each type of penetration seal during walkdowns, and that the scope of the inspections be expanded if any sign of seal degradation is detected. LRA Section B.2.1.17 states that not less than 10 percent of each type of penetration seal is inspected at least once per refueling cycle, except for internal conduit seals, which are not accessible for visual inspection. By letter dated January 17, 2012, the staff issued RAI B.2.1.17-2 requesting the applicant to explain how internal conduit seals that are not accessible for visual inspection are being managed for aging.

In its response, dated February 15, 2012, the applicant stated that the internal conduit seals are not exposed to high temperatures or relative motion and, therefore, are not subject to hardening, loss of strength, or loss of material. The applicant also stated that conduits that extend less than 5 feet on either side of the fire barrier are sealed with at least 9 inches of silicone foam and conduits that extend more than 5 feet from the fire barrier are sealed with at least 2 inches of silicone foam on both sides of the barrier. Therefore, the length of the seal makes it unlikely that degradation would provide a leak pathway. The applicant further stated that its NRC-approved fire protection program specifically excludes internal conduit seals from visual inspection. The staff noted that internal conduit seals are designed to prevent the passage of smoke and hot gases through the conduit using noncombustible material seals, whereas penetration seals seal the conduit to the fire barrier at the penetration and must have a fire resistance rating equal to that of the fire barrier. The staff also noted that the inaccessibility and thickness of internal conduit seals protects them from potential aging effects. The staff finds the applicant's response acceptable because inaccessible internal conduit seals have no aging effects that could affect their intended function to prevent passage of smoke and hot gasses.

The "detection of aging effects" program element of GALL Report AMP XI.M26 states that visual inspections are performed by fire protection qualified personnel of fire barrier penetration seals, walls, ceilings, floors, doors, and other fire barrier materials. LRA Section B.2.1.17 states that the personnel performing inspections are qualified and trained to perform the inspection activities. However, the staff noted that the personnel responsible for performing fire barrier inspections are maintenance qualified personnel; not fire protection qualified personnel. By letter dated January 17, 2012, the staff issued RAI B.2.1.17-3 requesting the applicant to describe the training and qualifications of the personnel responsible for performing fire barrier inspections.

In its response, dated February 15, 2012, the applicant stated fire barrier inspection parameters and acceptance criteria are identified in plant procedures and are consistent with Fire Protection program requirements. Any inspections that do not meet the established acceptance criteria are reviewed and evaluated by the fire protection program engineer, who is qualified under the Fire Protection program. The applicant also stated that inspections typically are performed by personnel who are qualified by training and demonstration of installation and repair of fire barriers, the purpose of fire barriers, fire barrier types, and materials of construction, and who inspect both new and repaired fire barriers. It was not clear to the staff how the applicant ensures that only personnel who are trained and qualified to identify fire barrier deficiencies are assigned to perform fire barrier inspections given that the personnel are only typically qualified. By letter dated March 22, 2012, the staff issued followup RAI B.2.1.17-3.1 requesting the applicant to explain the minimum qualifications required for the personnel performing fire barrier inspections, not the typical qualifications, and how the applicant ensures that only personnel trained and qualified to identify fire barrier deficiencies are assigned to perform fire barrier inspections.

In its response, dated March 30, 2012, the applicant stated that inspections are performed by maintenance and security personnel in accordance with site procedures consistent with the Fire Protection program requirements. Maintenance personnel who perform fire barrier inspections have at least 3 years of experience and are trained in accordance with the industry standards described in ACAD 92-008, "Guidelines for Training and Qualification of Maintenance Personnel," which includes training in plant fire systems, fire barriers, the CAP, and the use of plant procedures. The applicant also stated that security personnel perform inspections of fire barriers that also serve as security barriers. Security personnel who perform fire barrier inspections are trained by observation of inspections performed by a trained security officer, performance of an inspection while being observed by a trained security officer, and demonstration and completion of inspection procedure requirements. The applicant further stated that personnel verify they are qualified before performing fire barrier inspections and supervisors also verify the individuals assigned to perform the inspections are qualified. The applicant also stated that the inspections are performed in accordance with the fire protection barrier inspection parameters and acceptance criteria implemented by the Fire Protection program requirements. The staff finds the applicant's response acceptable because the maintenance and security personnel who perform fire barrier inspections have been qualified by training and experience to perform the required inspections and the applicant verifies that the personnel performing the inspections are qualified before performing the inspections; and any inspection results that do not meet the established acceptance criteria implemented in accordance with the Fire Protection program requirements are reviewed and evaluated by the fire protection program engineer. The staff's concerns described in RAIs B.2.1.17-3 and B.2.1.17-3.1 are resolved.

The staff also reviewed the portions of the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," "acceptance criteria" program elements associated with the 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.

Enhancement 1. LRA Section B.2.1.17 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the LRA states that additional inspection guidance will be provided to identify degradation of fire barrier walls, ceilings, and floors for aging effects such as cracking, spalling, and loss of material. GALL Report AMP XI.M26 recommends visual inspections of fire barrier walls, ceilings, and floors be performed to identify cracking, spalling, and loss of material. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP.

Enhancement 2. LRA Section B.2.1.17 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant stated that additional inspection guidance will be provided for identification of excessive loss of material from the external surfaces of the halon and carbon dioxide systems. GALL Report AMP XI.M26 recommends that periodic visual inspections of the halon and carbon dioxide systems be performed to identify any signs of corrosion. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M26 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.17-1, B.2.1.17-2, B.2.1.17-3, and B.2.1.17-3.1, 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 GALL Report AMP XI.M26. In addition, the staff reviewed the enhancements associated with the "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.2.1.17 summarizes operating experience related to the Fire Protection program. In one operating experience example, the LRA states that a gouge was identified in a foam fire barrier penetration seal during walkdown by the fire protection program engineer. As a result of the finding, additional inspections were performed that identified damage to another foam fire barrier penetration seal. The seals were declared inoperable pending engineering evaluation and corrective actions were taken to repair the seals. In another operating experience example, the LRA states that two tears were identified in the fabric covering a fire barrier. The tears were documented in the CAP and the applicant determined that the tears did not compromise the ability of the underlying fire barrier to perform its intended function.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.17 provides the UFSAR supplement for the Fire Protection program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 17) to enhance the program before the period of extended operation to 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; and to identify excessive loss of material caused by corrosion on the external surfaces of the halon and carbon dioxide systems. 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 Fire Protection 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 GALL Report AMP XI.M26. 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. 17 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.8 Fire Water System

Summary of Technical Information in the Application. LRA Section B.2.1.18 describes the existing Fire Water System program as consistent, with enhancements, with GALL Report AMP XI.M27, "Fire Water System." The LRA states that the program manages aging for the water-based fire protection system components exposed to outdoor air and raw water using periodic inspections, preventive measures, monitoring, and performance testing. The LRA also states that system functional tests, flow tests, flushes, and inspections are performed in accordance with applicable NFPA codes and standards and that the program includes fire system main header flow tests, sprinkler system inspections, visual yard hydrant inspections, hydrant flow tests, and volumetric inspections to ensure that aging effects are managed. The LRA further states that selected portions of the aboveground piping exposed to water will be inspected using volumetric examination to ensure aging effects are being managed and that wall thickness is within acceptable limits.

Staff Evaluation. During its audit, 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.M27. 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 the 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.

Enhancement 1. LRA Section B.2.1.18 states an enhancement to the "parameters monitored or inspected" and "detection of aging effects" program elements. In this enhancement, the applicant stated that sprinkler heads will be replaced or tested using the guidance in NFPA 25, "Standard for the Inspection, Testing, and Maintenance of Water-Based Fire Protection Systems," 2002 Edition, Section 5.3.1.1.1, by the 50-year inservice date and every 10 years thereafter. GALL Report AMP XI.M27 recommends that a sample of sprinkler heads that have been in place for 50 years be tested using the guidance in NFPA 25, 2002 Edition, Section 5.3.1.1.1. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP.

Enhancement 2. LRA Section B.2.1.18 states an enhancement to the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, the applicant stated that selected portions of the aboveground water-based fire protection system piping will be inspected using nonintrusive volumetric examinations before the period of extended operation and every 10 years thereafter. GALL Report AMP XI.M27 recommends that water-based fire protection system piping be flow tested in accordance with NFPA 25 or wall thickness evaluations be performed to ensure aging effects are managed and that wall thickness is within acceptable limits. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M27 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report AMP.

Based on its audit and review of the Fire Water System program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M27. 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.2.1.18 summarizes operating experience related to the Fire Water System program. In one operating experience example, the LRA states that inspection of a pre-action system's sprinkler heads identified over-spray on the sprinkler heads that could have prevented activation of the sprinkler heads. The affected sprinkler heads were replaced and the work order associated with application of the spray-on coating was revised to ensure that the areas not being coated are protected. In another operating experience example, the LRA states that a fire hydrant flow test identified a post-indicator valve that was not fully closing; therefore, causing a downstream hydrant to remain filled with water. The leaking valve was replaced before the potential for freezing could occur in the downstream hydrant.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.18 provides the UFSAR supplement for the Fire Water System program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 18) to enhance the Fire Water System program to replace sprinkler heads that have been inservice for 50 years or to perform testing in accordance with NFPA 25 and to inspect selected portions of the water-based fire protection system piping located aboveground using nonintrusive examinations before the period of extended operation and every 10 years thereafter. 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 Fire Water System program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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. 18 to implement the enhancement before the period of extended operation. 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).

3.0.3.2.9 Aboveground Metallic Tanks

Summary of Technical Information in the Application. LRA Section B.2.1.19 describes the existing Aboveground Metallic Tanks program as consistent, with enhancements with GALL Report AMPXI.M.29, "Aboveground Metallic Tanks." The LRA states that the AMP addresses metallic tanks exposed to outdoor air and soil environments to manage the effects of loss of material. The LRA also states that the AMP proposes to manage this aging effect through periodic visual inspections, tank bottom UT inspections, and the application of paint as a preventive action.

Staff Evaluation. During its audit, 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.M29.

For the "preventive actions" and "detection of aging effects" 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.M29 recommends installation of sealant or caulking at the tank to foundation interface to minimize the amount of water and moisture penetrating the interface, which could lead to corrosion of the tank bottom. However, during its audit, the staff found that the Aboveground Metallic Tanks program states that there is no caulking or sealant at the base of the backup water storage tank. By letter dated January 17, 2012, the staff issued RAI B.2.1.19-1 requesting the applicant to state the basis for concluding that there is a reasonable assurance that the backup water storage tank will be capable of performing its CLB function(s) in the absence of sealant or caulking at the tank's base.

In its response, dated February 15, 2012, the applicant stated that (a) the bottom of the backup water storage tank is coated with bitumastic asphalt coating, (b) to demonstrate that loss of material does not occur on the bottom of the backup water storage tank, a minimum of two tank bottom ultrasonic inspections will be performed, (c) the first inspection will be conducted within 5 years before entering the period of extended operation with a followon inspection 5 years later, and then, recurring inspections on 5-year intervals if necessary, (d) the inspection scope will include measurements around the circumference, on each plate, and at any locations with damaged internal coatings, (e) if after two inspections, no loss of material is detected on the bottom of the tank, future inspections will occur whenever the tank is drained, and (f) the UFSAR supplement, LRA Section A.2.1.19 and Enhancement No. 1 in LRA Section B.2.1.19 were revised to reflect the inspection plan as stated above in (b), (c), and (e).

The staff finds the applicant's response acceptable because (a) the bottom of the backup water storage tank is coated, which can result in reduced corrosion, (b) a minimum of two tank bottom volumetric inspections will be conducted, (c) the inspection locations cover a sufficient range of locations on the tank bottom, (d) conducting the first two inspections in the 5-year period before and at the start of the period of extended operation provides adequate time for corrosion to have occurred and been detected if the coatings and sand bed had not been effective, and (e) inspections will continue on a 5-year interval if loss of material on the bottom of the tank is detected. The staff's concern described in RAI B.2.1.19-1 is resolved.

The “detection of aging effects” program element in GALL Report AMP XI.M29 recommends that the external surface of the tank be visually inspected at each outage to confirm that the paint is intact. However, during its audit, the staff found that the Aboveground Metallic Tanks program states that to provide for visual inspection of the external surface of the backup water storage tank on a 2-year frequency, insulation will be removed on a sampling basis. By letter dated January 17, 2012, the staff issued RAI B.2.1.19-2 requesting the applicant to state how much insulation will be removed from the backup water storage tank during its 2-year frequency external surface inspections and state the basis for why the amount of insulation to be removed is sufficient to detect potential tank exterior degradation before it affects the ability of the tank to perform its CLB function(s).

In its response, dated February 15, 2012, the applicant stated that the tank is coated with an organic zinc-rich primer covered by enamel and insulated by a spray-on polyurethane foam type insulation with a fiberglass fabric outer layer. The inspection before entering the period of extended operation will consist of removing approximately 1 square foot of insulation in 25 locations and conducting a visual examination. The inspection locations will consist of areas where the insulation is intact and areas where the insulation shows visible signs of degradation. A minimum of 10 locations will be selected near the base of the tank where moisture intrusion is most likely to occur. If these inspections demonstrate that the insulation system is effective in preventing moisture from contacting the tank's surface, the subsequent inspections, conducted on a 2-year frequency will consist of a minimum of four locations. The applicant also revised LRA Sections A.2.1.19 and B.2.1.19, and Commitment No. 19 to reflect the minimum number of inspections.

The staff finds the applicant's response and Enhancement 2 acceptable because (a) the tank is coated and, therefore, the proposed visual inspections are consistent with GALL Report AMP XI.M.29 once the insulation has been removed, (b) the areas that the applicant is selecting for inspection include degraded insulation locations and at least 10 locations near the bottom of the tank, both which represent the most likely areas for water intrusion that could result in degradation, (c) given the age of the tank, 25 inspection locations is sufficient to detect if degradation is occurring, (d) removing 1 square foot of insulation provides adequate area for a visual inspection, (e) inspections will be conducted on a 2-year frequency, and (f) the number of inspection locations will only be reduced below 25 to 4 if the initial inspection demonstrates that the insulation is effective as a moisture barrier. The staff's concern described in RAI B.2.1.19-2 is resolved.

The staff also reviewed the portions of the “scope of program,” “preventive actions,” “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.

Enhancement 1. LRA Section B.2.1.19 states an enhancement to the “scope of program,” “detection of aging effects,” “monitoring and trending,” and “acceptance criteria” program elements. In this enhancement, as amended by its response to RAI B.2.1.19-1, the applicant stated that it will conduct UT measurements of the bottom of the backup water storage tank once within 5 years before the period of extended operation followed by a followup inspection within 5 years. If loss of material is detected, inspections will continue on a 5-year interval. If no loss of material is detected, inspections will be conducted whenever the tank is drained. The staff reviewed this enhancement against the corresponding program elements in GALL Report

AMP XI.M29 and noted that the "detection of aging effects" program element recommends that the inspection of the tank should occur within 5 years of entering the period of extended operation. The staff finds this enhancement acceptable because during the audit, the staff confirmed that this tank had been installed early during the construction period and thus it has sufficient service time that conducting a UT exam 5 years before the period of extended operation would not prevent the program from being able to detect potential plant-specific degradation.

Enhancement 2. LRA Section B.2.1.19 states an enhancement to the "scope of program," "preventive actions," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements. In this enhancement, as amended by its response to RAI B.2.1.19-2, the applicant stated that on a sampling basis, every 2 years it will remove insulation from the tank to permit a visual inspection of the tank's surface. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M29 and its evaluation is documented above in RAI B.2.1.19-2.

Based on its audit and review of the applicant's responses to RAIs B.2.1.19-1 and B.2.1.19-2, 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 GALL Report AMP XI.M29. In addition, the staff reviewed the enhancements associated with the "scope of program," "preventive actions," "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.2.1.19 summarizes operating experience related to the Aboveground Metallic Tanks program. The applicant stated that a June 2000 underwater inspection of the tank's internal surfaces conducted by a diver determined that the internal coatings were in excellent condition. The applicant also stated that a September 2007 visual inspection was conducted on the internal surfaces of the tank when it was drained. No deterioration of the tank's surface coatings was identified.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.19 provides the UFSAR supplement for the Aboveground Metallic Tanks program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 19) to enhance the program to (a) conduct UT measurements of the backup water storage tank's bottom within 5 years before entering the period of extended operation and 5 years thereafter, unless no loss of material on the tank bottom is found during these first two inspections whereupon followon inspections will occur whenever the tank is drained, and (b) on a sampling basis, every 2 years remove insulation from the tank to permit a visual inspection of the tank's surface.

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 Aboveground Metallic 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 GALL Report AMP XI.M29. 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. 19 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.10 Fuel Oil Chemistry

Summary of Technical Information in the Application. LRA Section B.2.1.20 describes the existing Fuel Oil Chemistry program as consistent, with enhancements, with GALL Report AMP XI.M30, "Fuel Oil Chemistry." The LRA states that the program manages loss of material in piping, piping elements, piping components, and tanks in a fuel oil environment. The applicant also stated that the fuel oil tanks within scope are maintained by monitoring and controlling fuel oil contaminants in accordance with the technical specifications, technical requirements, and American Society for Testing and Materials (ASTM) guidelines. It was indicated that fuel oil sampling and analysis is performed in accordance with approved procedures for new fuel oil and stored fuel oil. Furthermore, it was stated that fuel oil tanks are periodically drained of accumulated water and sediment, cleaned, and internally inspected.

Staff Evaluation. During its audit, 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.M30.

For the "detection of aging effects," program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "detection of aging effects," program element in GALL Report AMP XI.M30 states that periodic multilevel sampling provides assurance that fuel oil contaminants are below unacceptable levels. If tank design features do not allow for multilevel sampling, a sampling methodology that includes a representative sample from the lowest point in the tank may be used. However, during its audit, the staff found that the Fuel Oil Chemistry program states that the samples for analysis are taken by running the fuel oil transfer pumps, which take suction 11 inches from the bottom of the emergency diesel generator diesel oil storage tanks, to transfer fuel oil to a sample collection point in the emergency diesel generator day tank room, which may not provide a representative sample. By letter dated January 17, 2012, the staff issued RAI B.2.1.20-1 requesting that the applicant explain how the current LGS sample collection methodology assures that fuel oil contaminants are below unacceptable levels, as is recommended in GALL Report AMP XI.M30.

In its response dated February 15, 2012, the applicant stated that the fuel oil transfer pump is a sump pump that takes suction 11 inches from the bottom of the emergency diesel generator oil storage tank. It was stated that there are no design features on the tanks such as process piping or drains that would allow for sampling at a lower tank elevation. The applicant stated that the GALL Report AMP XI.M30 recommends ASTM standard D 4057-95, "Manual Sampling of Petroleum and Petroleum Products" for sampling methods. The applicant stated that this standard discusses various levels of sampling methodologies, which would constitute a multilevel sample. In reviewing this standard, the applicant stated that the LGS sample method is more conservative than the multilevel sample methods described in ASTM D 4057-95, because the LGS method takes samples at heights that are equivalent or at lower levels of the tank than the levels called out in the standard. In addition, the LGS sample method does not take composite samples of the tank, which are called out in the ASTM standard, but rather, the samples are solely taken from 11 inches from the bottom of the tank where contaminants tend to collect and settle.

The staff finds the applicant's response acceptable because this method of sampling takes samples from a suction that is 11 inches from the bottom of the emergency diesel generator diesel oil storage tanks, where contaminants, water, and sediments, tend to settle. In addition, taking bottoms samples as opposed to composite tank samples is consistent with the GALL Report, because contaminants, water, and sediments may be detected. As such, the staff finds that the sampling used by the Fuel Oil Chemistry program is equivalent or more conservative than the sampling method recommended by GALL Report AMP XI.M30. The staff's concern described in RAI B.2.1.20-1 is resolved.

The staff also reviewed the portions of the "preventative actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" 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.

<u>Enhancement 1</u>. LRA Section B.2.1.20 states an enhancement to the "preventative actions" program element. In this enhancement, the applicant stated that water will be periodically drained from the fire pump engine diesel oil day tank and the fire pump diesel engine fuel tank. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

<u>Enhancement 2</u>. LRA Section B.2.1.20 states an enhancement to the "preventative actions" and "detection of aging effects" program elements. In this enhancement, the applicant stated that internal inspections will be performed for 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. The applicant also stated that each diesel fuel tank will

be drained, cleaned, and the internal surfaces either volumetrically or visually inspected. It was indicated that if evidence of degradation is observed during visual inspections, the diesel fuel tanks will require followup volumetric inspection. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 3. LRA Section B.2.1.20 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this enhancement, the applicant stated that periodic analysis will be performed for total particulate concentration and microbiological organisms for the fire pump engine diesel oil day tank and the fire pump diesel engine fuel tank. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 4. LRA Section B.2.1.20 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this enhancement, the applicant stated periodic analysis will be performed for water and sediment and microbiological organisms for the diesel generator diesel oil storage tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 5. LRA Section B.2.1.20 states an enhancement to the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements. In this enhancement, the applicant stated that periodic analysis will be performed for water and sediment, total particulate concentration, and microbiological organisms for the diesel generator day tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 6. LRA Section B.2.1.20 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that an analysis will be performed 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. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Enhancement 7. LRA Section B.2.1.20 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that an analysis will be performed on new fuel oil for total particulate concentration and the levels of microbiological organisms for the diesel generator diesel oil storage tanks. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.M30 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M30.

Based on its audit, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M30. In addition, the staff reviewed the enhancements associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.20 summarizes operating experience related to the Fuel Oil Chemistry program.

The applicant stated that in April 2008, the D12 diesel generator diesel oil storage tank 1B-T527 was drained, cleaned, and inspected. It was stated that the activities included an inspection of coatings by a certified coatings inspector and a tank internal inspection by a certified Pennsylvania tank inspector. It was reported that the internal condition of the tank was acceptable. Furthermore, it was indicated that the inspection revealed no evidence of degradation.

In May 2008, it was reported that the D24 diesel generator diesel oil storage tank 2D-T527 was drained, cleaned, and inspected. It was stated that the activities included an inspection of coatings by a certified Pennsylvania tank inspector. It was reported that the internal condition of the tank was acceptable. Furthermore, it was indicated that the coating inspection revealed a chip in the coating at the base of the tank. This condition was entered into the CAP, evaluated by engineering, and found to be acceptable without repair. The applicant stated that tracking and trending of the rusting around the chip area was recommended.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, operating experience related to the applicant's program that demonstrates it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.20 provides the UFSAR supplement for the Fuel Oil Chemistry program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 20) to implement the seven enhancements discussed above 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 Fuel Oil Chemistry program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation will make the AMP adequate to manage the applicable aging effects and the UFSAR supplement contained Commitment No. 20 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.11 Monitoring of Neutron-Absorbing Materials Other than Boraflex

Summary of Technical Information in the Application. LRA Section B.2.1.28 describes the existing Monitoring of Neutron-Absorbing Materials Other than Boraflex program as consistent, with enhancement, with GALL Report AMP XI.M40, "Monitoring of Neutron-Absorbing Materials Other than Boraflex." The applicant stated that this program periodically analyzes test coupons of the Boral material in the LGS Units 1 and 2 spent fuel racks to determine if the neutron-absorbing capability of the material has degraded. It was stated that the program ensures that a 5 percent subcriticality margin is maintained in the spent fuel pool.

The applicant stated that this program monitors the physical condition of the Boral material in the spent fuel racks by analysis of test coupons for physical attributes, neutron attenuation testing, dimensional checks, and weight and density characteristics. It was reported that the primary measurements for characterizing the performance of the Boral are the coupon thickness measurements and neutron attenuation tests. The applicant stated that the acceptance criteria are for neutron attenuation results to show that a decrease of no more than 5 percent of Boron-10 content has occurred, and the dimensional measurements show that an increase in thickness at any point does not exceed 10 percent of the initial thickness at that point.

Staff Evaluation. During its audit, 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.M40.

For the "parameters monitored or inspected," "detection of aging effects," and "monitoring and trending" program elements, the staff determined the need for additional information, which resulted in the issuance of RAI B.2.1.28-1, as discussed below.

The program elements in GALL Report AMP XI.M40 state that for neutron absorber materials, gamma irradiation or long-term exposure to the wet pool environment may cause loss of material and changes in dimension (such as gap formation, formation of blisters, pits, and bulges) that could result in loss of neutron-absorbing capability of the material. However, during its audit, the staff found that the applicant's Boral coupon trees in the Units 1 and 2 spent fuel pools (SFPs) are located in a "representative" location rather than a "bounding" location. That is, the coupon tree location is expected to receive a uniform gamma flux representative of typical rack exposure. The program is not clear on whether the coupon exposure to the environment is bounding for the Boral material in all racks. By letter dated January 30, 2012, the staff issued RAIs B.2.1.28-1 requesting the applicant to discuss how the coupon exposure (i.e., coupon tree location) will provide reasonable assurance that Boral degradation is identified before potential loss of neutron-absorbing capability of the material.

In its response letter, dated February 28, 2012, the applicant stated that in order for the coupons to obtain environmental conditions bounding of all Boral spent fuel pool racks, it proposes to resume an accelerated exposure configuration for the Boral coupons (i.e., surround the coupons by freshly discharged fuel assemblies) at each of the next five refueling cycles, beginning with the refueling outage in 2014 and 2013 for LGS Units 1 and 2, respectively.
The staff reviewed this response and determined the need for more information. The coupons in the LGS Units 1 and 2 spent fuel pools may not have experienced long exposure to high radiation fluence from freshly discharged fuel compared to the most limiting storage cell, making the exposure time potentially nonconservative or not bounding of all the LGS Unit 1 and 2 Boral spent fuel pool racks; therefore, they may not provide acceptable testing data for monitoring loss of material and degradation of the neutron-absorbing material capacity. By letter dated April 13, 2012, the staff issued followup RAI B.2.1.28-2 requesting the applicant to provide justification on how resuming a five cycle radiation exposure period will place the coupons in a bounding condition for all Boral spent fuel pool racks for the LGS Units 1 and 2 for the period of extended operation.

In its response letter, dated April 27, 2012, the applicant stated that plant documentation on fuel pool inventory was reviewed, and it was determined that the actual number of cycles that the coupons were completely surrounded by freshly discharged fuel for LGS Unit 2 is five (first five cycles following rack installation), and for LGS Unit 1 is two (first two cycles following rack installation). The applicant then stated that surrounding the test coupons by eight freshly discharged fuel bundles for five future cycles (ending 2024 and 2023 for LGS Units 1 and 2, respectively) will ensure that the test coupons will be leading indicators for other individual fuel storage cells.

The applicant stated that an analysis was performed on the spent fuel pool inventory relative to the test coupons to predict when the exposure of the coupons to freshly discharged fuel would be equal to the exposure of the limiting storage cells to freshly discharged fuel. It was concluded that the coupons in the SFP will be exposed to the same number of freshly discharged fuel assemblies as the theoretical worst case cell in 2020 for LGS Unit 1 and 2021 for LGS Unit 2.

The staff reviewed this response and determined the need for more information. Although the applicant provided a path forward for coupon exposure such that the coupons would be the leading indicator for other individual fuel storage cells for LGS Units 1 and 2, it did not provide the relative cumulative dose of the coupons compared to the most limiting storage cell. By letter dated May 18, 2012, the staff issued RAI B.2.1.28-3 requesting the applicant to discuss the relative cumulative dose for the coupons compared to the most limiting storage cell at the end of the proposed five cycles of exposure to freshly discharged fuel. Also, it was requested that the applicant discuss the impact of an accelerated exposure to freshly discharged fuel versus a long-term exposure to representative conditions.

In its response letter dated May 31, 2012, the applicant stated that the coupons will have been exposed to a greater number of freshly discharged fuel assemblies than the worst case fuel storage cell after the next five cycles of exposure, before the period of extended operation. The applicant further stated that documented industry research does not differentiate between accelerated and long term exposure effects. The applicant stated that there are no documented analyses that indicate gamma heating or other effects from radiation exposure are the likely cause of degradation of Boral. Moreover, the applicant stated that the most recent documented analyses of operating experience relating to degradation of Boral attribute the most likely causes of the degradation to manufacturing practices. The applicant cited industry research that states that although degradation of Boral can lead to minor corrosion and blistering, leading to reduced clearance between assemblies, it has no effect on the intended function of neutron absorption. The applicant stated that the coupon testing proposed for LGS is consistent with the GALL Report and will monitor the condition of the Boral spent fuel storage cell during the period of extended operation for the following reasons:

- The coupons will be bounding of the most limiting fuel storage cell location relative to radiation exposure.
- The coupons are exposed to the same environment conditions as the Boral panels in the fuel storage cells, relative to being submerged in water within a fuel storage cell. Since the water within the pool is continually circulated, the temperature of the water at the coupons is similar to the temperature of the Boral panels in the fuel storage cells.
- The next coupon test will be performed after the exposure to radiation to the coupons is known to be bounding of the most limiting fuel storage cell and before the start of the period of extended operation.
- Coupon testing will continue to be performed at a frequency not to exceed 10 years during the period of extended operation as recommended by GALL Report AMP XI.M40.
- Coupon testing includes analyses for physical attributes, dimensional checks and neutron attenuation that are designed to identify loss of material, loss of neutron absorption ability, and the types of degradation observed at other plants, as described above.

Although the data cited by the applicant indicates that Boral defects are likely a result of the manufacturing process, the staff maintains that all neutron absorbing materials should be monitored for degradation of their neutron attenuation capability. While the industry research on Boral may strengthen the argument that the material is robust, the staff's evaluation is based on the adequacy and representative nature of the applicant's coupon surveillance program.

The staff finds the applicant's response acceptable because performing neutron attenuation testing is an acceptable means to evaluate neutron attenuation. The staff finds the evaluation of the coupon's physical attributes and dimensional measurements acceptable because these attributes and measurements allow the material condition to be determined. In addition, the applicant has demonstrated that the coupons will be exposed to similar environmental conditions as the Boral in the fuel storage cells. Moreover, the coupons will be surrounded by eight freshly discharged fuel bundles for five future cycles (ending 2024 and 2023 for LGS Units 1 and 2, respectively) making the coupons leading indicators for potential degradation of the Boral in the fuel storage cells. The testing frequency was reviewed and was determined to be consistent with the recommendations of the GALL Report. The staff finds acceptable that the applicant evaluates operating experience of Boral neutron absorber material in other similarly operated nuclear plants to inform the LGS program. The staff's concern described in RAI B.2.1.28-3 is resolved

The staff also reviewed the portions of the "detection of aging effects" and "corrective actions" 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 the enhancements follows.

Enhancement 1. LRA Section B.2.1.28 states an enhancement to the "detection of aging effects" program. In this enhancement, the applicant stated that testing and analysis of Boral coupons will be performed on a 10-year frequency, beginning no earlier than 2020 for Unit 1 and 2021 for Unit 2. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M40 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP XI.M40.

Enhancement 2. LRA Section B.2.1.28 states an enhancement to the "corrective actions" program element. In this enhancement, the applicant stated that corrective actions will be initiated if coupon test result data indicates that acceptance criteria will be exceeded before the next scheduled test coupon analysis. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M40 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.M40.

Enhancement 3. LRA Section B.2.1.28 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that LGS will 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). The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M40 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.M40.

Enhancement 4. LRA Section B.2.1.28 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that LGS will 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. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.M40 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.M40.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.28-1, B.2.1.28-2, and B.2.1.28-3, the staff finds that the program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.M40. In addition, the staff reviewed the enhancements associated with the "detection of aging effects," "monitoring and trending," and "corrective actions" program elements and finds that when implemented, they will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.28 summarizes operating experience related to the Monitoring of Neutron-Absorbing Materials Other than Boraflex program.

The applicant stated that an analysis of a test coupon removed from the LGS, Unit 2 SFP in 2001 included an evaluation of physical attributes, neutron attenuation testing, dimensional checks, and weight and density characteristics of the coupon. It was indicated that after 7 years of service, the Boral absorbers in the storage racks had retained their dimensional and neutron-absorption properties and were capable of continuing to perform their intended function of controlling reactivity. Similar results were reported in 1999 and 1997.

The applicant stated that Information Notice 2009-26, "Degradation of Neutron-Absorbing Materials in the Spent Fuel Pool," was addressed through the CAP. As a result, it was stated that the current optional spent fuel pool test coupon analysis program will be implemented for both units.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.28 provides the UFSAR supplement for the Monitoring of Neutron-Absorbing Materials Other than Boraflex program. In its response letter dated April 27, 2012, the applicant provided revisions to the UFSAR supplement and commitment. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 28) to enhance the program by;

(1) Performing test coupon analysis on a 10-year frequency, beginning no earlier than 2020 for Unit 1 and 2021 for Unit 2.

(2) Initiating corrective actions if coupon test result data indicates that acceptance criteria will be exceeded before the next scheduled test coupon analysis.

(3) Resuming 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).

(4) Maintaining 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.

The applicant stated that the enhancements will be implemented 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 Monitoring of Neutron-Absorbing Materials Other than Boraflex 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 GALL Report AMP XI.M40. 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 contained Commitment No. 28 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).

3.0.3.2.12 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, and visual inspections of the pipe during opportunistic excavations; and 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.

Staff Evaluation. During its audit, 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 action" program element in GALL Report AMP XI.M41 recommends that buried steel piping be coated and cathodically protected. However, 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 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 CLB despite a lack of cathodic protection and coatings for the plant drainage system and lack of coating 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 NACE SP0169-2007, and the plant drainage piping is not cathodically protected because it is constructed from cast iron, a corrosion-resistant material.

The staff finds the applicant's response acceptable because both piping systems are coated with coatings recommended by NACE SP0169-2007 as recommended by GALL Report AMP XI.M41. While 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), 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 recommends that if adverse indications are detected, inspection sample sizes within the affected piping categories are doubled, and if adverse indications are found in the expanded sample, the inspection sample size is again doubled, with the doubling of the inspection sample size continuing as necessary. However, 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 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 consistent with GALL Report AMP XI.M41, or to state why the corrective action 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 what was intended by the wording associated with the CAP. GALL Report AMP XI.M41, Section 4.f.iv. states, "[i]f adverse indications are detected, 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 necessary." It was not clear if 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," because it does not appear to be consistent with GALL Report AMP XI.M41.

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 and B.2.1.29 accordingly.

The staff finds the applicant's response acceptable because the enhancement is now consistent with the wording in AMP XI.M41, Section 4.f.iv. The staff's concern described in RAI B.2.1.29.1 is resolved.

The "acceptance criteria" program element in GALL Report AMP XI.M41 recommends that cathodic protection system soil to pipe potential acceptance criteria be consistent with NACE SP0169-2007. NACE SP0169-2007, Section 7.1.2.7, states that excessive levels of cathodic protection can cause external coating disbondment. However, during its audit, the staff found that the applicant's "Cathodic Protection Design Basis Document" states 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 finds 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 is 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.

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, states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that, "[i]f adverse indications are detected, 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 necessary." The staff reviewed this enhancement as amended by the responses to RAI B.2.1.29-2, provided by letter dated February 15, 2012, and RAI B.2.1.29-2.1, provided by letter dated March 22, 2012, 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 the wording in AMP XI.M41, section 4.f.iv.

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 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 Table 2b, Preventive Actions for Underground Piping and Tanks, which recommends that underground piping be coated in accordance with NACE standards.

Enhancement 3. 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. Visual inspections will be performed by a NACE qualified inspector. 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 the visual inspection of external and volumetric inspection of internal surfaces recommendations of AMP XI.M41.

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 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 finds 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. 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 visual inspections of safety-related SW piping will be performed by a NACE-qualified inspector. During the audit, the staff reviewed "before" pictures of this piping showing external surface degradation and "after" pictures with the external corrosion removed and coatings applied. The applicant stated that it was in the process of completing inspections and coating all of this piping. 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, as recommended by AMP XI.M41, it will ensure that potential coating degradation will be evaluated by an individual qualified to conduct the inspections.

Enhancement 6. 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 are reliable 90 percent of the time. 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 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 SER, RAI B.2.1.29-3 was issued requesting the applicant to 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 finds it acceptable because when it is implemented, it will be consistent with NACE SP0169-2007 which is recommended by GALL Report AMP XI.M41 and industry guidelines for cathodic protection.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.29-1, B.2.1.29-2, B.2.1.29-3, and B.2.1.29-2.1, 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 GALL Report AMP XI.M41. 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 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 operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.29 provides the 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 recommended description in SRP-LR Table 3.0-1.

The staff also noted that the UFSAR supplement contained a commitment (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 GALL Report AMP XI.M41. 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).

3.0.3.2.13 ASME Code Section XI, Subsection IWE

Summary of Technical Information in the Application. LRA Section B.2.1.30 describes the existing ASME Code Section XI, Subsection IWE program as consistent, with enhancements, with GALL Report AMP XI.S1, "ASME Code Section XI, Subsection IWE." The LRA states that the AMP addresses the inspection of primary containment components exposed to uncontrolled indoor air and treated water environments to manage the effects of age-related degradation because of loss of material caused by corrosion, loss of preload in the bolts, and loss of leak-tightness. The LRA also states that the AMP proposes to manage this aging effect through periodic visual inspections. When visual examination results require an evaluation or the component is repaired and is found to be acceptable for continued service, the areas containing such flaws, degradation, or repair are reexamined during the next inspection period. According to ASME Code Section XI, Subsection IWE, each "inspection period" and "inspection interval" are of 40 months and 120 months duration, respectively.

The primary containment components inspected in accordance with this AMP are the Class MC pressure-retaining components and their integral attachments, including wetted surfaces of submerged areas of the pressure suppression chamber and vent system, diaphragm slab carbon steel liner, downcomers and bracing, containment hatches and airlocks, drywell head, penetration sleeves, pressure retaining bolting, and other pressure retaining components.

Staff Evaluation. During its audit, 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.S1. For the "scope of program," "monitoring and trending," and "acceptance criteria" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs about the following subjects:

- Liner Plate Recoating Criteria
- Liner Plate Corrosion Degradation Acceptance and Augmented Inspection Criteria
- Liner Plate General and Pitting Corrosion Rate
- Downcomers Corrosion
- Suppression Pool Columns Corrosion

The details of the RAIs and the applicant's responses to these RAIs are documented in the following:

(1) the NRC's letter to the applicant, dated January 30, 2012 (Adams Accession No. ML11364A099)

(2) Exelon's letter to the NRC, dated February 28, 2012 (Adams Accession No. ML12059A345)

(3) the NRC's letter to the applicant, dated April 16, 2012 (Adams Accession No. ML12082A155)

(4) Exelon's letter to the NRC, dated April 27, 2012 (Adams Accession No. ML12121A009)

(5) Exelon's letter to the NRC, dated September 12, 2012 (Adams Accession No. ML12256A929)

(6) The NRC's letter to the applicant, dated October 19, 2012 (Adams Accession No. ML12290A853)

(7) Exelon's letter to the NRC dated October 25, 2012 (Adams Accession No. ML12299A393)

In response to staff's RAIs, the applicant revised its ASME Code Section XI, Subsection IWE aging management program to manage aging of the suppression pool liner and coating system. Specifically, the applicant enhanced the program to provide an expedited schedule for locally recoating the suppression pool liner plate in areas affected by corrosion to impede further corrosion, added criteria for augmented examination of the liner plate and recoating of downcomers, and committed to perform ultrasonic thickness examination to complement liner plate thickness measured using depth gauges. The applicant also revised Commitment No. 30 to include all these changes. The staff found the revised AMP and Commitment No. 30 acceptable. The details of the staff's evaluation to determine acceptability of the revised AMP and Commitment No. 30 is described below.

Liner Plate Corrosion Rate and Recoat Acceptance Criteria. During the audit, the staff noted that general corrosion and pitting (local general corrosion) was recorded on the floor and walls of the 1/4 inch (250 mils) thick carbon steel liner plate in the LGS Unit 1 suppression pool. Most of the pits were less than 50 mils deep, and there were hundreds of pits that were less than 30 mils. One of the pits was 122 mils deep, while some others were about 70 mils deep. Many plates had general corrosion; the level of corrosion ranged between 72 percent of the surface for one floor plate to zero percent for some wall plates.

The applicant had previously reviewed the liner plate design, performed calculations to disposition the suppression pool carbon steel liner plate corrosion degradation, and concluded the following:

- For pitting corrosion, the area shall be recoated when the metal loss is 1/8 inch (125 mils lost and 125 mils remain).
- For pitting corrosion, the area shall be repaired (metal repair) when the metal loss is 3/16 inch (187.5 mils lost and 62.5 mils remain).
- For general corrosion, the area shall be repaired (metal repair) when metal loss is 1/8 inch (125 mils lost and 125 mils remain).

As part of a separate licensing action, the staff has previously reviewed the above noted criteria and found it acceptable as documented in a letter dated February 20, 2008 (ADAMS Accession No. ML080310769). As long as these criteria are met, the liner plate will perform its function. The staff used this approved criteria in its determination whether the actions proposed by the applicant were sufficient to manage the aging effect of loss of material.

To manage degradation and corrosion of the liner plate during the period of extended operation, the applicant committed (Commitment No. 30) to enhance the existing ASME Code Section XI, Subsection IWE program, submitted as a part of the LRA in June 2011, to:

Manage the suppression pool liner and coating system to:

(1) Remove any accumulated sludge in the suppression pool every refueling outage.

(2) Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period.

(3) Use the results of the ASME IWE examination to implement a coating maintenance plan to:
    - Perform local recoating of areas with general corrosion that exhibit greater than 25 mils plate thickness loss.
    - Perform spot recoating of pitting greater than 50 mils deep.
    - Recoat plates with greater than 25 percent coating depletion.

The coating maintenance plan will be initiated in the 2012 refueling outage for Unit 1, and the 2013 refueling outage for Unit 2, and implemented such that the areas exceeding the above criteria are recoated before the period of extended operation. The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss.

The staff reviewed Commitment No. 30 and noted that the applicant plans to recoat the locally corroded areas of the carbon steel liner plate to prevent further corrosion and loss of thickness. However, the staff was concerned about the delay between identifying a location that met the criteria for recoating and the completion of the recoating of the suppression pool carbon steel liner plate until the period of extended operation in selected areas where general corrosion is already more than 25 mils and pitting corrosion more than 50 mils. Therefore, the staff requested the applicant to address the acceptability of delaying recoating the liner plate by 12 years for Unit 1 and 17 years for Unit 2, in areas that have already exceeded the recoating criteria described in Commitment No. 30. Pitting (local corrosion) corrosion rates are much higher than general corrosion rates and may lead to penetration and leakage of the liner if the recoating of the corrosion affected areas is not completed until 2024 for Unit 1 and 2029 for Unit 2.

In its last response on this subject, the applicant revised Commitment No. 30 to:

Manage the suppression pool liner and coating system to:

(1) Remove any accumulated sludge in the suppression pool every refueling outage.

(2) Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period.

(3) Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following before the period of extended operation:

- 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 Code Section XI, Subsection IWE, Category E-C.
- 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 areas of general corrosion will also be used to determine when the submerged portions of the liner require augmented inspection in accordance with ASME Code Section XI, Subsection IWE, Category E-C.
- 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.

(4) Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the period of extended operation:

- 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 Code Section XI, Subsection IWE, Category E-C.
- 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 Code Section XI, Subsection IWE, Category E-C.
- For plates with greater than 25 percent coating depletion, the affected area will be recoated no later than the next scheduled inspection.

The coating maintenance plan will be initiated in the 2012 refueling outage for Unit 1 and the 2013 refueling outage for Unit 2. The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss.

The staff reviewed the revised Commitment No. 30, as noted above, and found it acceptable because:

(1) The applicant plans to recoat all local areas (less than 2.5 inches in diameter) of corrosion (pitting corrosion) that are greater than 50 mils plate thickness loss in 2012 for Unit 1, and 2013 for Unit 2.

(2) The applicant has committed to perform an ASME IWE examination of the submerged portion of the suppression pool during each ISI period or at a maximum interval of 4 years (two refueling outages).

(3) The maximum 4-year inspection interval is sufficiently short to identify local (pitting) corrosion before challenging the structural integrity and leak tightness of the liner, as described in the following:

> Any local areas (less than 2.5 inches in diameter) of corrosion that are less than 50 mils plate thickness loss, and thus would not be recoated, can have an additional loss of thickness of 137.5 mils before the 187.5 mil pitting threshold is reached. The staff previously approved calculations that demonstrated that this level of pitting corrosion is acceptable. If the 187.5 mils threshold is reached or exceeded, the local area would be repaired.
> To sustain an additional metal loss of 137.5 mils over a 4-year inspection interval, the local (pitting) corrosion has to exceed a rate of 34 mils per year. The staff noted that, in the controlled suppression pool water environment, pitting of carbon steel would likely be expected to occur only beneath deposits where a differential aeration cell is formed and local areas of aggressive water chemistry could be created. In water environments more aggressive than that of the suppression pool, under-deposit corrosion rates up to approximately 0.3 mm/year (12 mils/year) have been observed (Uhlig's Corrosion Handbook, Second Edition, pg. 541, 566). According to the applicant, the maximum individual spot corrosion rate measured since 1995 for Unit 2, and 1996 for Unit 1, is 2.1 mils per year.
>
> The staff considers it reasonable to assume a maximum local (pitting) corrosion rate of 12 mils per year until additional data and trends are established based on future IWE inspections of the Unit 1 and Unit 2 suppression pools. This is nearly one-third of the allowable rate of 34 mils per year. In addition, the applicant is committed to recoat local areas with metal loss of more than 50 mils identified during any IWE inspection immediately during the same outage to prevent further degradation and corrosion. Recoating of the local areas of corrosion in the outage they are identified will prevent further degradation and loss of thickness. Therefore, IWE inspection of areas of local (pitting) corrosion at a maximum interval of 4 years is acceptable.

(4) The maximum 4-year inspection interval is sufficiently short to identify general corrosion before challenging the structural integrity and leak tightness of the liner, as described in the following:

> The applicant is committed to recoat areas of the liner plate with general corrosion that exhibit more than 25 mils average plate thickness loss based on ranking of affected surface area, high to low before the period of extended operation. After the period of extended operation, these areas will be recoated in the outage they are identified. According to the IWE inspections performed until 2010, the greatest loss of material caused by general corrosion for Unit 1 and Unit 2 liner plates is 35 mils total. The applicant has also collected data for general corrosion of the LGS suppression pool liner plates since 1995 that indicate a general corrosion rate of 2 mils per year. Therefore, even if the general corrosion is allowed to continue until 2029 in Unit 2 and the affected areas of the liner are not recoated, the total loss in thickness will be 73 (35+2*19 years) mils. The applicant has performed calculations that were previously approved by the staff, and have concluded that areas with general corrosion in the liner plate up to 125 mils are acceptable without repair. Therefore, even in the worst case that the applicant does not recoat the areas of general corrosion until the period of extended operation of Unit 2 in 2029, the structural integrity of the suppression pool liner plate will be maintained. After the period of extended operation, any plate with general corrosion will be recoated in the outage it is identified. The total loss in thickness caused by general corrosion between the IWE inspections (maximum duration 4 years) is not expected to be more than 8 mils.

(5) The applicant committed to recoat areas of liner plates with greater than 25 percent coating depletion based on ranking of affected surface area depleted and metal thickness loss before the period of extended operation. After the start of the period of extended operation, areas with greater than 25 percent coating depletion will be recoated no later than the next scheduled inspection. The staff finds this acceptable because recoating will be performed proactively on areas of the liner that have less than 25 mil loss in thickness or 10 percent of liner plate thickness. The structural integrity or leak tightness of the suppression pool is a function of liner plate thickness and is not challenged by loss of coating or loss in thickness of 25 mils or less.

Liner Plate Corrosion Degradation and Coating Inspection. The staff was concerned about the quality and methods used for the underwater visual inspection performed by the applicant for the suppression pool liner plate. The applicant provided the following information about this issue in its September 12, 2012, letter:

(1) The contractor used for underwater inspections maintains a Quality Assurance Program that is reviewed and approved by the applicant and meets the requirements of 10 CFR 50, Appendix B. The personnel performing the visual examination of the liner plate and coating are qualified and certified in accordance with the requirements of ANSI N45.2.6 and ASTM D4537.

(2) A visual VT-3 examination is performed to determine the general condition of the coating. Any corrosion observed is considered as indicative of loss of coating. For local areas, the inspector identifies the size of area containing the indications, the size of

indications, and the quantity of indications within the area. This data is documented and coating loss is identified as percentage of the total area examined. For larger areas, characterization of the area is performed consistent with the methods described in ASTM D610/SSPC VIS-2.

(3) During the VT-3 examination, the inspectors also identify areas with or approaching substantial corrosion. The applicant has defined substantial corrosion as general corrosion greater than 25 mils average loss of thickness, or local areas of general corrosion greater than 50 mils loss. The inspectors use a go/no-go gauge as necessary to report a bounding condition. Augmented visual VT-1 examination of the areas identified with substantial corrosion is performed. This is accomplished by use of calibrated depth dial gauge to determine the loss in thickness.

(4) To demonstrate that loss of thickness of the liner plate measured by calibrated depth gauge underwater is appropriate, the applicant performed ultrasonic measurements in 2012 on four Unit 1 plates in areas of general corrosion. The results of UT examination were compared with those obtained from visual examination using a calibrated depth gauge. It was found that the calibrated depth gauge method recorded comparatively greater loss in thickness and provided conservative results.

In its letter dated October 25, 2012, the applicant also revised the AMP and Commitment No. 30 to state that the ASME Code Section XI, Subsection IWE aging management program will be enhanced prior to the PEO to perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. The ultrasonic thickness measurement requirements will be implemented before receipt of the renewed licenses.

The staff finds the detailed information provided by the applicant concerning the quality and methods acceptable because:

(1) The suppression pool liner plate inspection is performed by qualified personnel who are approved by the applicant and meet the requirements of 10 CFR 50, Appendix B. The personnel performing the inspection underwater are trained and qualified in accordance with the requirements of ANSI N45.2.6 as required by ASME Code Section XI, Subsection IWA, Article IWA-2300 and 10 CFR 50.55a.

(2) As required by IWE-3511, the applicant has defined acceptance criteria for augmented visual examination as areas of general corrosion greater than 25 mils average loss of thickness, or local areas of general corrosion greater than 50 mils loss. This is based on calculations performed by the applicant that demonstrate that the corrosion rate is such that it will not jeopardize the intended function of the liner plate and will remain leak tight until the next inspection period. If corrosion exceeds the augmented inspection criteria, the applicant will recoat the liner appropriately as discussed earlier in this section to maintain the liner leak tight.

(3) The applicant will perform detailed visual VT-1 examination of the areas requiring augmented inspection as required by IWE-2500. In addition, the applicant will perform UT thickness measurements on four areas of the suppression pool liner that are affected by general corrosion to correlate with visual VT-1 examination results and provide confidence in the VT-1 examination thickness measurements using a calibrated depth gauge.

Downcomers Corrosion. During the audit, the staff reviewed a CAP-generated assignment report that indicated that there was corrosion of the suppression pool downcomers. Therefore, the staff requested through three rounds of separate RAIs that the applicant provide additional information concerning the extent of corrosion, acceptance criteria used for evaluating the corrosion, and technical basis for the acceptance criteria for the downcomers. In response to the staff's RAIs, the applicant stated that the acceptance criterion used for the initial visual examination of the downcomers in the 1R13 outage, as reported in the assignment report, is less than or equal to 60 mils. The technical basis of this owner-established criterion is the design analyses for the downcomers in four original design basis calculations. These analyses conclude that surface defects of less than or equal to 62.5 mils are acceptable to meet design requirements. The corrosion found on the downcomers during 1R13 (2010) outage affected less than 13 percent of the cumulative surface area examined. Loss of metal in the exposed substrate was generally less than 15 mils.

In its letter dated October 25, 2012, the applicant also revised the AMP and Commitment No. 30 to use the results of the ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:

- 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 Code Section XI, Subsection IWE, Category E-C.
- 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 Code Section XI, Subsection IWE, Category E-C. The downcomer recoat and augmented inspection criteria will be implemented before receipt of the renewed licenses.

The staff finds the applicant's response concerning owner-established criteria for the recoating of downcomers acceptable because it is based on original design calculations and supplemental analysis. The structural integrity of the downcomers (375 mils in nominal wall thickness) will not be compromised by loss of material caused by local corrosion of up to 40 mils and loss of material caused by general corrosion of 30 mils. The original design was based on a loss of up to 62.5 mils in the thickness of the downcomers caused by surface defects. In addition, the applicant will have to recoat downcomers with local areas (less than or equal to 5.5 inches in any direction) that have 40 mils or more metal thickness loss or areas of general corrosion (greater than 5.5 inches in any direction) that have loss of material of 30 mils or more. The recoating will be done during the refueling outage in which it is discovered because ASME Section XI, Subsection IWE, Article IWE-3112(b) requires that a component whose examination detects flaws or areas of degradation that do not meet the owner's defined acceptance criteria shall be corrected prior to placement of the component in service.

Suppression Pool Columns Corrosion. During the audit, the staff reviewed a CAP-generated assignment report that indicated corrosion of the suppression pool columns and requested the applicant to provide additional information. The applicant stated in response to two rounds of RAIs that minimal general corrosion and spot corrosion (affecting less than 1.5 percent of the cumulative surface area inspected) was identified on the 12 columns (42-inch diameter hollow steel pipe columns) examined in Unit 1. General loss of material was reported at less than 20 mils, and no localized corrosion exceeding 60 mils was identified. The applicant has used a loss of 62.5 mils as the acceptance criteria for loss of thickness of suppression pool columns caused by corrosion because original construction specification permitted surface defects of less than or equal to 62.5 mils. The applicant also stated that the small areas of minimal general corrosion identified on the 1.25-inch wall thickness of the hollow steel pipe columns do not affect load-bearing capacity or visibly reduce the cross-sectional area, and are, therefore, acceptable. The applicant further stated that the examination frequency for the suppression pool columns is each inspection interval (120 months) which is in accordance with ASME Code Section XI, Subsection IWF, Table IWF-2500-1 for item F1.40.

The staff finds the applicant's response to the RAIs concerning the current condition of the suppression pool support columns acceptable because general corrosion loss of 20 mils is equivalent to less than 2 percent of the 1.25-inch thick columns, and will not affect the load-carrying capacity of the columns. ASME Code, Section XI, Subsection IWF states that components are acceptable for continued service if the roughness or general corrosion does not reduce the load-bearing capacity of the support and general conditions are acceptable by the material, design, or construction specification. In addition, localized corrosion not exceeding 60 mils is acceptable because the original construction specification permitted surface defects of less than 62.5 mils.

In its response, dated April 27, 2012, the applicant stated that the examination frequency for the suppression pool columns is each inspection interval (120 months), which is in accordance with ASME Code Section XI, Subsection IWF, Table IWF-2500-1 for item F1.40. The staff finds this acceptable because the suppression pool support columns will be examined at the frequency specified in the ASME Code. The applicant is also using the acceptance criteria specified in the ASME Code Section XI, Subsection IWF, which states that components are acceptable for continued service if the roughness or general corrosion does not reduce the load-bearing capacity of the support and general conditions are acceptable by the material, design, or construction specification.

Enhancements. The staff also reviewed the portion of the "preventive actions," and "detection of aging effects," program element associated with the 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.

Enhancement 1. LRA Section B.2.1.30, as amended by letters dated September 12, 2012, and October 25, 2012, states an enhancement to the "detection of aging effects," program element will be implemented before the period of extended operation to manage the suppression pool liner and coating system. This will include more frequent inspections and selected recoating of the corroded areas of the suppression pool. This will be initiated in the 2012 refueling outage for LGS Unit 1 and the 2013 refueling outage for LGS Unit 2. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S1 and found it acceptable. The basis for the staff's determination is described earlier in this section.

Enhancement 2. LRA Section B.2.1.30, as amended by letter dated October 25, 2012, states that an enhancement to the "detection of aging effects," program element will be implemented before receipt of the renewed licenses for recoating and augmented inspection of the downcomers. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S1 and found it acceptable. The basis for the staff's determination is described earlier in this section.

Enhancement 3. LRA Section B.2.1.30, as amended by letter dated October 25, 2012, states that an enhancement to the "detection of aging effects," program element will be implemented before the receipt of the renewed licenses to perform UT thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S1 and found it acceptable. The basis for the staff's determination is described earlier in this section.

Enhancement 4. LRA Section B.2.1.30 states an enhancement to the "preventive actions," program element. In this enhancement, the applicant stated that ASME Code Section XI, Subsection IWE program will be enhanced to 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. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S1 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in the GALL Report by ensuring the proper specifications are used. In addition, as documented in SER Section 3.0.3.2.3, the applicant revised the LRA to state that high-strength bolting, if used, will be monitored for cracking. The applicant further stated that other pressure-retaining bolting is inspected for leakage, which could result from cracking.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.30-1, B.2.1.30-1.1, B.2.1.30-2, B.2.1.30-2.1, RAI B.2.1.30-2.2, B.2.1.30-3, B.2.1.30.4-1, B.2.1.30.4-1, RAI B.2.1.30-6, and RAI B.2.1.30-7, 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 GALL Report AMP XI.S1. In addition, the staff reviewed enhancements 1 through 4 and finds them acceptable, as discussed earlier in this section.

Operating Experience. LRA Section B.2.1.30 summarizes operating experience related to the ASME Code Section XI, Subsection IWE program. This included focused self-assessment that resulted in enhancement of the ASME Code Section XI, Subsection IWE program's scope, detection of corrosion in the suppression pool liner plates that was evaluated and some areas recoated to prevent additional loss of material, and identification and subsequent tightening of the loose bolts on the access manway located on the LGS Unit 2 drywell head. The LRA stated these examples demonstrate that the ASME Code Section XI, Subsection IWE program has been able to identify aging effects and that corrective actions were taken under the program to prevent the recurrence of component failures.

During its review, the staff identified operating experience for which it determined the need for additional clarification, which resulted in the issuance of an RAI, as discussed below.

During the audit, the staff reviewed the ASME Code, Section XI, Subsection IWE (Class MC) containment visual examination NDE report for different components, including one for the drywell closure head. This report had photographs of the different attachments to the drywell closure head that show extensive corrosion and pitting. However, the examination report found that the condition is acceptable by visual examination. The staff was concerned about this assessment and by letter dated January 30, 2012, issued RAI B.2.1.30-5 requesting the applicant explain the basis for acceptance of extensive corrosion and pitting on the different attachments to the drywell closure head.

In its response dated February 28, 2012, the applicant stated that the pictures of the LGS Unit 2 drywell head included with the examination report of this component for the April 2011 outage depict surface corrosion on the ends of a steel support angle and channel support for a ladder and platform that are attachments to the drywell closure head. No pitting is depicted in the photograph and none was noted by the examiner. The implementing procedure acceptance criterion for the drywell head states that localized areas of corrosion shall not exceed 0.050 inches. This surface corrosion was determined to be within the acceptance criterion by the examiner as no loss of thickness or pitting was noted. Although the surface corrosion of the ladder and platform supports and their attachment points on the drywell head are acceptable, this condition had been entered into the CAP for follow up.

The staff finds the applicant's response acceptable because the applicant provided the basis for acceptance of the corrosion on the different attachments. There was no loss of thickness or pitting recorded by the examiner, and this condition has been entered into the CAP for followup inspection and assessment. The staff's concern described in RAI B.2.1.30-5 is resolved.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.30-5, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.30, as amended by letter dated October 25, 2012, provides the UFSAR supplement for the ASME Code Section XI, Subsection IWE AMP. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. 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 ASME Code Section XI, Subsection IWE AMP, 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 GALL Report AMP XI.S1. In addition, the staff reviewed enhancements 1-4 and Commitment No. 30 and determined them to be acceptable, as discussed earlier in this section. The staff also reviewed the UFSAR supplement for this AMP and concluded that it provides an adequate summary description of the program.

3.0.3.2.14 ASME Code Section XI, Subsection IWL

Summary of Technical Information in the Application. LRA Section B2.1.31 describes the existing ASME Code Section XI, Subsection IWL program as consistent, with an enhancement, with GALL Report AMP XI.S2, "ASME Code Section XI, Subsection IWL." The LRA states that the ASME Code Section XI, Subsection IWL program is an existing condition monitoring program that implements examination requirements of the ASME Code. The inspection methods, inspected parameters, and acceptance criteria in this program are in accordance with

ASME Code, Section XI, Subsection IWL. Periodic general visual examination of the containment accessible concrete surfaces to detect deterioration and distress as defined in American Concrete Institute (ACI) 201.1 and ACI 349.3R-02. The concrete of the primary containments are exposed to an indoor air environment sheltered within the reactor enclosure. The LRA further states that the current ASME Code, Section XI, Subsection IWL containment ISI program complies with ASME Code, Section XI, Subsection IWL, 2001 Edition including 2003 Addenda as approved by 10 CFR 50.55a. In accordance with 10 CFR 50.55a(g)(4)(ii), the ISI program is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code, 12 months before the start of the inspection interval.

Staff Evaluation. During its audit, 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.S2. For the "acceptance criteria" program element, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "acceptance criteria" program element in GALL Report AMP XI.S2 recommends using ACI 349.3R-02 for identification of concrete degradation. However, during its audit, the staff noted that the applicant's program basis document and implementing procedure exclude the first-tier acceptance criteria defined in ACI 349.3R-02 "Evaluation of Existing Nuclear Safety-Related Concrete Structures," for concrete surface examination. By letter dated January 30, 2012, the staff issued RAI B.2.1.31-1 requesting the applicant to provide justification for excluding the first-tier acceptance criteria for the primary containment concrete surface examination as described in ACI 349.3R-02, Chapter 5, "Evaluation Criteria."

In its response dated February 28, 2012, the applicant stated that it meets the recommendations of ACI 349.3R-02, Chapter 5, for use of the second-tier criteria because: (a) the 6-foot 2-inch thick conventionally reinforced concrete walls of the primary containment constitute massive concrete, (b) the environment within the reactor enclosure is indoor air; therefore, the primary containment structures are not exposed to degradation mechanisms, which would be applicable to an outdoor air or seacoast environment as described in ACI 349.3R-02, and (c) the specified minimum concrete cover is 2 inches, which is in excess of the minimum concrete cover specified in ACI 349.3R-02. The applicant stated that all three factors in Chapter 5 of ACI 349.3R-02 for excluding the first-tier acceptance criteria are met; therefore, application of the second-tier acceptance criteria is justified for the purpose of evaluation of observed conditions of the primary containments.

The staff finds the applicant's response acceptable because the applicant confirmed that the implementation of the first-tier acceptance criteria could be overly conservative for (a) the massive concrete structures, (b) structures not exposed to certain degradation mechanisms, or (c) structures possessing concrete cover in excess of the minimum requirements of ACI 349.3R-02, such as concrete containment structures. Therefore, the staff finds that all three factors in Chapter 5 of the ACI 349.3R-02 are met, and use of the second-tier acceptance criteria is justified for the primary containments' concrete. The staff's concern described in RAI B.2.1.31-1 is resolved.

The "acceptance criteria," program element in GALL Report AMP XI.S2 relies on the determination of the "Responsible Engineer" as defined by the ASME Code. However, during the audit, the staff noted that the site procedures did not clearly define the qualification requirements of the "Responsible Engineer." By letter dated January 30, 2012, the staff issued RAI B2.1.31-2 to confirm whether the "Responsible Engineer" meets the qualification requirements of ASME Code, Section XI, Subsection IWL-2300.

In its response dated February 28, 2012, the applicant stated that the procedure defines a Responsible Engineer as "[a] Registered Professional Engineer as defined in ASME Code Section XI Subsection IWL experienced in evaluating the inservice condition of structural concrete. The Responsible Engineer shall have knowledge of the design and construction codes and other criteria used in the design and construction of concrete containment structures in nuclear power plants." The applicant further stated that this definition is in accordance with the requirements of ASME Code Section XI, Subsection IWL 2320, and the procedure governs conduct of all ASME Code Section XI ISI activities, and is an implementing procedure for GALL Report AMP XI.S2, ASME Code Section XI, Subsection IWL.

The staff finds the applicant's response acceptable because the applicant defined the Responsible Engineer in the procedure, which is in accordance with the requirements of Subsection IWL-2320 of the ASME Code, Section XI. The staff's concern described in RAI B.2.1.31-2 is resolved.

Enhancement. LRA Section B.2.1.31 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that the ASME Code, Section XI, Subsection IWL program will be enhanced to include the second-tier acceptance criteria of the ACI 349.3R-02. As discussed above, the staff issued RAI B2.1.31-2 requesting the applicant to provide justification for excluding the first-tier acceptance criteria of the primary containment concrete as required in Chapter 5, "Evaluation Criteria" of ACI 349.3R-02. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S2, and the applicant's response to RAI B2.1.31-2, and finds it acceptable because when it is implemented, it will meet the requirements of ACI 349.3R-02 and, therefore, be consistent with GALL Report AMP XI.S2.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.31-1 and B.2.1.31-2, of the ASME Code Section XI, Subsection IWL program, the staff finds the elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S2. In addition, the staff reviewed the enhancement associated with the "acceptance criteria" program element and finds that when implemented, it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.31 summarizes operating experience related to the ASME Code Section XI, Subsection IWL program. The operating experience summary identified a number of areas where minor concrete surface imperfections, including random scattered hairline cracking, minor surface voids, popouts, and scaling have been observed previously. The conditions were found either to be within acceptance criteria without a need for evaluation, or the findings were evaluated by the Responsible Engineer and it was determined that the structural integrity of the containments were acceptable. The LRA also states that examples of these operating experiences demonstrate that the ASME Code Section XI, Subsection IWL program will be effective in ensuring that intended functions will be maintained consistent with the CLB for the period of extended operations.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicant reviewed the applicable aging effects and industry and site specific operating experience. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff identified operating experience for which it determined the need for additional clarification and resulted in the issuance of an RAI as discussed below.

The staff reviewed an issue report during the audit that identified corrosion and degradation of the steel metal deck (Q-deck), abandoned structural steel members attached to the underside of the concrete diaphragm slab above the suppression pool. Since the diaphragm slab is a part of the containment boundary and is included in the scope of ASME Code Section XI, Subsection IWL program, the staff was concerned about the effect of the degraded Q-deck and abandoned steel members on the emergency core cooling system (ECCS) through the period of extended operation. By letter dated January 30, 2012, the staff issued RAI B.2.1.31-3 requesting information for the following issues:

(1) Identify the effects of Q-deck degradation on the concrete diaphragm slab, including potential degradation of rebar.

(2) Discuss how the corrosion from the Q-deck and other abandoned steel structures attached to the ceiling of the suppression pool would impact the corrosion-product inventory in the suppression pool and the operation of the current ECCS suction strainers through the period of extended operation.

In its response dated February 12, 2012, the applicant stated that the Q-deck and the abandoned steel on the underside of the concrete diaphragm slab are included within the scope of license renewal and subject to aging management using the Structures Monitoring program. The applicant also stated that it has evaluated the condition of the Q-deck and found that the surface corrosion noted was acceptable and does not affect the structural integrity of the concrete diaphragm slab. The reinforcing steel embedded in the diaphragm slab is located above the Q-deck, and is not in contact with it. In addition, the shear studs embedded in the concrete are raised above the Q-deck, such that concrete separates the reinforcing steel from the Q-deck. The shear studs embedded in the diaphragm slab are also not attached to the metal decking but rather are attached to the structural steel beams that are within the scope of license renewal and subject to the Structures Monitoring program. Therefore, the corrosion noted on the metal decking (Q-deck) will have no effect on the concrete diaphragm slab and reinforcing steel.

Regarding the concern about the potential impact of corrosion particles from the Q-deck on the ECCS suction strainers, the applicant stated that it has previously performed an evaluation that concluded that the corrosion from the Q-deck particles is bounded by the corrosion product inventory allowance for the ECCS suction strainers. In addition, the suppression pool floor and ECCS suction strainers are periodically inspected for sludge and foreign material accumulation. LRA Appendix A.5, Commitment No. 30 also requires removal of any accumulated sludge from the suppression pool every refueling outage. Therefore, there is no impact on the corrosion product inventory allowance and no impact on the operation of the ECCS suction strainers through the period of extended operation.

The staff finds the applicant's response acceptable because the Q-deck is included within the scope of license renewal, and aging management is addressed by the Structures Monitoring program. The surface corrosion on the Q-deck is acceptable, and has no impact on the structural integrity of the concrete diaphragm slab. The reinforcing steel in the diaphragm slab are not in contact with the Q-deck, and therefore, is not likely to be degraded or corroded. Additional degradation, if any, of the Q-deck and structural steel beams will be managed by the Structures Monitoring program during the period of extended operation.

The corrosion from the Q-deck particles is bounded by the corrosion product inventory allowance in the design of the ECCS suction strainers. In addition, the existing ASME Code Section XI, Subsection IWE program will be enhanced to include removal of any accumulated sludge from the suppression pool every refueling outage to ensure that there is no impact on the operation of the ECCS suction strainers through the period of extended operation. The staff's concern described in RAI B.2.1.31-3 is resolved.

Based on its audit and review of the application and review of the applicant's response to RAI B.2.1.31-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.31 provides the UFSAR supplement for the ASME Code Section XI, Subsection IWL program. The staff reviewed this UFSAR supplement description of the program against the recommended description for this type of program as described in SRP-LR Table 3.0-1. The staff also noted that the UFSASR contained a commitment (Commitment No. 31) to enhance the existing ASME Code Section XI, Subsection IWL program to include the second-tier acceptance criteria of ACI 349.3R-02 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 ASME Code Section XI, Subsection IWL program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR contained Commitment No 31 to implement the enhancement before the period of extended operation. 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 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).

3.0.3.2.15 ASME Code Section XI, Subsection IWF

Summary of Technical Information in the Application. LRA Section B.2.1.32 describes the existing ASME Code Section XI, Subsection IWF program as consistent, with an enhancement, with GALL Report AMP XI.S3, "ASME Code Section XI, Subsection IWF." The LRA states that the program consists of periodic visual inspections for loss of material and loss of mechanical function for ASME Code, Section XI Class 1, 2, 3, and MC piping and component support members. The program also includes management of loss of material and loss of preload for structural bolting by inspecting for missing, detached, or loosened bolts and nuts. The LRA also states that the program includes preventive measures to ensure proper specification of bolting material, lubricant, and proper installation torque. The program was developed and implemented to comply with ASME Code, Section XI, Subsection IWF, 2001 Edition through the 2003 Addenda, as approved in 10 CFR 50.55a, and as such, is updated each successive 120-month inspection interval to comply with the requirements of the latest edition of the ASME Code specified twelve months before the start of the inspection interval.

Staff Evaluation. During its audit, 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.S3. For the "scope of program" and "preventive actions" program elements, the staff determined the need for additional information, which resulted in the issuance of RAIs, as discussed below.

The "scope of program" element in GALL Report AMP XI.S3 recommends that metal containment (MC) supports be examined as part of the ASME Code Section XI, Subsection IWF program. The "scope of program" element of the LRA AMP basis document states that the applicant examines MC piping and support members. However, during its audit, the staff found that the applicant's program procedures specifically exempt MC supports from the scope of the ASME Code Section XI, Subsection IWF program. By letter dated January 30, 2012, the staff issued RAI B.2.1.32-1 requesting the applicant to explain why class MC supports are not included in the implementing documents for the ASME Code Section XI, Subsection IWF program and how these components will be managed for aging during the period of extended operation.

In its response dated February 28, 2012, the applicant stated that its procedures have been revised to clarify that ASME Code Class MC supports are visually inspected in accordance with the ASME Code Section XI, Subsection IWF program. The staff finds the applicant's response acceptable because the ASME Code Section XI, Subsection IWF program implementing procedures have been revised to include visual inspections of Class MC supports in accordance with ASME Code Section XI, Subsection IWF and the GALL Report recommendations. The staff's concern described in RAI B.2.1.32-1 is resolved.

GALL Report AMP XI.S3 recommends that the program include visual inspections of high-strength structural bolting (actual measured yield strength greater than or equal to 150 ksi or 1,034 MPa) for cracking. The "preventive actions" program element in GALL Report AMP XI.S3 recommends that for high-strength structural bolting consisting of ASTM A325, ASTM F1852, and/or ASTM A490 bolts, the preventive actions for storage, lubricants, and SCC potential discussed in Section 2 of the Research Council for Structural Connections (RCSC) publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts" need to be used. However, during its audit, the staff found discrepancies between program elements of the ASME Code Section XI, Subsection IWF program basis documents regarding the use of high-strength structural bolting. The "preventive actions" element states that structural bolting used in ASME Code Section XI, Subsection IWF program supports do not include ASTM A325, ASTM F1852, or ASTM A490 bolts. However, the "detection of aging effects" element states that while the use of high-strength bolts in supports is not common, A490 bolts are used for some larger supports. By letter dated January 30, 2012, the staff issued RAI B.2.1.32-2 requesting the applicant to state whether high-strength structural bolting is used in any ASME Code Section XI, Subsection IWF program supports, and if so, whether the preventive actions for storage, lubricants, and SCC potential discussed in Section 2 of RCSC publication, "Specification for Structural Joints Using ASTM A325 or A490 Bolts" are followed.

In its response dated February 28, 2012, the applicant stated that the structural bolting for ASME Code Section XI, Subsection IWF program supports do not include the use of ASTM A325, ASTM F1852 or ASTM A490 bolts, and that the "detection of aging effects" element of the AMP basis document will be revised to state that the structural bolting for ASME Code Section XI, Subsection IWF program supports does not include the use of ASTM A325, ASTM F1852, or ASTM A490 bolts. The staff reviewed the applicant's response, as well as relevant portions of the LGS Units 1 and 2 UFSAR. In Table 3.9-6 of the UFSAR, several locations either call out SA325 bolts (the ASME equivalent to ASTM A325), or reference ASME Code, Division III, Subsection NF, which allows the use of SA325 bolts. It appears to the staff that there may be a discrepancy between the information in the UFSAR, and the information provided in the response to RAI B.2.1.32-2. Therefore, by letter dated June 5, 2012, the staff issued RAI B.2.1.32-2.1 requesting the applicant to verify no ASTM A325, F1852 or A490 bolts are within the scope of the ASME Code Section XI, Subsection IWF program. If those bolts are within the scope of the program, the applicant was requested to explain how the preventive actions discussed in Section 2 of the RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts," would be addressed.

By letter dated June 14, 2012, the applicant responded and stated that the bolts identified as SA3235 in the UFSAR were incorrectly identified. A walkdown and inspection of the bolts in question identified the bolts as ASTM A449. A CAP issue report was initiated to identify and resolve the discrepancy. The applicant further stated that for future installations or maintenance of supports within the scope of the ASME Code Section XI, Subsection IWF program may use material that is equivalent to ASTM A325. Therefore, the storage and handling preventive actions recommended in the GALL Report and the RCSC publication will be followed. The applicant explained that these recommendations are currently addressed by a commitment in the UFSAR supplement (Commitment No. 35), which applies to all carbon steel high-strength structural bolting, regardless of the ultimate use of the bolting material (i.e., Structures Monitoring program or ASME Code Section XI, Subsection IWF program supports).

The staff reviewed the applicant's response and noted that the Structures Monitoring program will be enhanced to incorporate the recommendations of the RCSC "Specification for Structural Joints Using ASTM A325 or A490 Bolts," into its guidance for storage and handling of all carbon steel high-strength structural bolts. The staff finds the applicant's response acceptable because the aging management for high-strength structural bolting within the scope of license renewal will be consistent with the GALL Report recommendations for preventive actions. The staff's concern described in RAI B.2.1.32-2.1 is resolved.

The staff also reviewed the portions of the "preventive actions" program element associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B.2.1.32 states an enhancement to the "preventive actions" program element. In this enhancement, the applicant stated that before the period of extended operation, the ASME Code Section XI, Subsection IWF program will be enhanced to 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. GALL Report AMP XI.S3 states that selection of bolting materials, lubricants, and sealants should be in accordance with EPRI NP-5769, EPRI TR-104213, and the additional recommendations of NUREG-1339 to prevent or mitigate degradation and failure of safety-related bolting. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S3 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations in GALL Report AMP by ensuring the proper specifications for structural bolting are used.

Based on its audit, and review of the applicant's responses to RAIs B.2.1.32-1 and B.2.1.32-2 of the applicant's ASME Code Section XI, Subsection IWF program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S3. In addition, the staff reviewed the enhancement associated with the "preventive actions" program element and finds that when implemented; it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.32 summarizes operating experience related to the ASME Code Section XI, Subsection IWF program. The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant.

As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. In one operating experience example, the LRA states that an inspection identified a cold load setting for one support to be outside the 10 percent acceptance criterion. The scope of the inspection was expanded and four additional supports were also found to be outside of the acceptance criteria. An engineering evaluation was performed and it was determined that the supports were acceptable in the as-found condition. However, the supports were returned to the correct cold load settings and were re-inspected and found satisfactory 2 years later.

During its audit, the staff noted several cases such as this in which conditions were found during ASME Code, Section XI, Subsection IWF examinations that appeared to be degraded, but where an engineering evaluation determined that the component was acceptable for continued service (i.e., did not violate the acceptance standards of ASME Code Section XI, Subsection IWF-3410) and the applicant chose to rework the component to its as-new condition. The ASME Code, Section XI, Subsection IWF program requires the inspection of the same sample of the total population of component supports each inspection interval. The staff determined that for effective aging management of the entire population, the condition of the component to be re-examined during each inspection interval should be representative of the aging of the entire population. If ASME Code Section XI, Subsection IWF program supports that are part of the inspection sample are reworked to as-new condition, that support is no longer typical of the other supports in the population that were not reworked, and in subsequent examinations would not represent the age-related degradation of that population. Therefore, by letter dated January 30, 2012, the staff issued RAI B.2.1.32-3 requesting the applicant to explain, when corrective actions are not required per the ASME Code, Section XI, Subsection IWF acceptance criteria, but a support within the inspection sample is found degraded and repaired to as-new condition without an expansion or revision of the sample population, how the ASME Code Section XI, Subsection IWF program will be effective in managing aging of similar/adjacent components in that population that are not included in the ASME Code Section XI, Subsection IWF program sample.

In its response dated February 28, 2012, the applicant stated that when component support conditions are found to include minor age-related degradation that does not meet the threshold of "unacceptable for continued service" as defined in ASME Code, Section XI, Subsection IWF-3400, an evaluation may be performed in accordance with the CAP. The applicant stated that it may choose to take actions on the subject component and will evaluate the need to substitute the support in subsequent inspections with a component that may be more representative of the general population. The applicant further stated that it will incorporate the above guidance into the AMP procedure, thus ensuring the ASME Code Section XI, Subsection IWF program is effective in managing aging of supports within the scope of the program. The staff finds this response acceptable because the applicant's program will ensure that the component supports being examined in the ASME Code Section XI, Subsection IWF program inspection sample are representative of the aging of the total population, thus allowing the program to adequately manage aging of supports and bolting within the scope of the program.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.32-3, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, operating experience related to the applicant's program that demonstrates it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.32 provides the UFSAR supplement for the ASME Code Section XI, Subsection IWF program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 32) to enhance the ASME Code Section XI, Subsection IWF program to 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 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 ASME Code Section XI, Subsection IWF program, the staff concludes that the program elements for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S3. Also, the staff reviewed the enhancement and confirmed that its implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR supplement contained Commitment No. 32 to implement the enhancement before the period of extended operation. 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).

3.0.3.2.16 Masonry Walls

Summary of Technical Information in the Application. LRA Section B.2.1.34 describes the existing Masonry Walls program as consistent, with enhancements, with GALL Report AMP XI.S5, "Masonry Walls." The LRA states that the AMP is a condition monitoring program that provides for visual inspection of masonry walls for loss of material and cracking, and is enhanced to inspect for shrinkage or separation and for gaps between the supports and masonry walls that could impact the intended function of the walls. The LRA further states that the program is administered as part of the Structures Monitoring program, is based on guidance provided in NRC Bulletin 80-11 and NRC Information Notice (IN) 87-67, and is implemented through station procedures. Environments include uncontrolled indoor air and outdoor air. The LRA also states that masonry walls considered fire barriers are managed by the Fire Protection program and that steel edge supports and steel bracing were not required or used as part of the masonry wall design.

Staff Evaluation. During its audit, 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.S5. The staff also reviewed the plant conditions to determine whether they are bounded by the conditions for which the GALL Report was evaluated.

The staff reviewed the portions of the "scope of program," "parameters monitored or inspected," "detection of aging effects," 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.

Enhancement 1. LRA Section B.2.1.34 states an enhancement to the "scope of program," program elements. In this enhancement, the applicant stated that the administration building warehouse, fuel oil pumphouse, and transformer foundation dike walls and structures that include masonry walls, would be added to the program scope. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, the masonry walls AMP will include all masonry walls for structures in scope for license renewal.

Enhancement 2. LRA Section B.2.1.34 states an enhancement to the "parameters monitored or inspected," and "acceptance criteria" program elements. In this enhancement, the applicant stated that it will provide additional guidance for inspection of masonry walls for shrinkage, separation, and for gaps between the supports and walls that could affect the wall's intended function. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, it will be consistent with industry standard and the GALL report.

Enhancement 3. LRA Section B.2.1.34 states an enhancement to the "detection of aging effects" program elements. In this enhancement, the applicant stated that the Masonry Wall program will have an inspection frequency of not greater than 5 years. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, the 5-year inspection frequency will bring the program into alignment with the guidance in ACI 349.3R, which is the industry standard.

Enhancement 4. LRA Section B.2.1.34 states an enhancement to the "detection of aging effects," program elements. In this enhancement, the applicant stated that program procedures will require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S5 and finds it acceptable because when it is implemented, it will bring the program into alignment with the guidance in ACI 349.3R, which is the industry standard.

Based on its audit of the Masonry Walls program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S5. In addition, the staff reviewed the enhancements associated with the "scope of program," "parameters monitored or inspected," "detection of aging effects," and "acceptance criteria" program elements and finds that when implemented, the AMP will be adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.34 summarizes operating experience related to the Masonry Walls program. The LRA states that structures monitoring inspections from 2007 through 2010 included inspections of masonry walls and identified no significant deficiencies. There have been a few instances of acceptable hairline surface cracks, but no other degradation or significant cracks were noted. The LRA states that cracking caused by impact from plant equipment was identified on a masonry wall dike and subsequently repaired. The structures monitoring inspections completed in 2006 also did not identify any unacceptable cracking or gaps in masonry walls; however, minor surface cracking was noted on masonry walls in the LGS Unit 2 turbine enclosure near the feed water heater area. The LRA states that the cracking was noted previously and no changes were observed.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. The staff also performed a walkdown of the turbine enclosure and noted the surface cracking referenced in LRA section B.2.1.34. The staff noted that the surface cracking is minor and that the applicant is monitoring the cracks for any changes in condition. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.34 provides the UFSAR supplement for the Masonry Walls program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1.

The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 34) to enhance the program by (1) adding to its scope the administration building warehouse, fuel oil pumphouse, transformer foundation dike walls, (2) providing 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, (3) requiring an inspection frequency of not greater than 5 years, and (4) requiring that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R. These enhancements will be implemented 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 Masonry Walls program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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. 34 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.17 Structures Monitoring

Summary of Technical Information in the Application. LRA Section B.2.1.35 describes the existing Structures Monitoring program as consistent, with enhancements, with GALL Report AMP XI.S6, "Structures Monitoring." The LRA states that the AMP through periodic monitoring assesses the condition of structures and structural components, structural bolting, component supports, masonry block walls, and elastomers exposed to outdoor air, uncontrolled indoor air, treated water, raw water, flowing water, and ground water and soil environments. The LRA further states that concrete is inspected for evidence of leaching, loss of material, cracking, and a loss of bond; steel components are inspected for loss of material caused by corrosion; masonry walls are inspected for cracking and loss of material; elastomers are monitored for hardening, shrinkage, and a loss of sealing; and per LRA update dated April 13, 2012, fiberglass fabric of the permanent drywell shielding blankets will be monitored for rips and tears. The program also provides for periodic testing and assessment of ground water chemistry and inspection of accessible below grade concrete structures. Inspections are conducted on a frequency not to exceed 5 years, and when warranted more frequently, to maintain structures' and components' intended function(s). Unacceptable conditions are corrected in accordance with the CAP.

The LRA also states that the AMP was developed to meet the regulatory requirements of 10 CFR 50.65, "Maintenance Rule," as well as the guidance contained in RG 1.160, "Monitoring the Effectiveness of Maintenance at Nuclear Power Plants," and in NUMARC 93-01, "Industry

Guideline for Monitoring the Effectiveness of Maintenance at Nuclear Power Plants." The program includes the inspection of masonry walls to be evaluated in accordance with NRC IEB 80-11, "Masonry Wall Design" and incorporates guidance of NRC IN 87-67, "Lessons Learned from Regional Inspection of Licensee Actions in Response to IE Bulletin 80-11." The LRA further states that the Structures Monitoring program will be enhanced for consistency with ACI 349.3R-02.

Staff Evaluation. During its audit, the staff reviewed the applicant's claim of consistency with the GALL Report. The staff compared program elements one through six of the applicant's program to the corresponding program elements of GALL Report AMP XI.S6. For the "monitoring and trending" program element the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "monitoring and trending" program element in GALL Report AMP XI.S6 recommends that the existing Structures Monitoring program monitor structures and components in accordance with 10 CFR 50.65 and RG 1.160 Revision 2, Regulatory Position 1.5; structures and components within the scope of the maintenance rule are to be monitored in accordance with 10 CFR 50.65(a)(2) if inspection results do not identify significant degradation; and the program is to contain provisions for increased inspection frequency and trending for structures and components in accordance with 10 CFR 50.65(a)(1). However, during its audit, the staff found that although the Structures Monitoring program recommends these actions, it was not clear that these statements are consistent because a plant-specific TLAA or inspection/surveillance program does not exist to provide assurances that the capability of the prestressed concrete girders associated with the SFP will continue to meet their intended function(s) during the period of extended operation. By letter dated January 30, 2012, the staff issued RAI B.2.1.35-1 requesting the applicant to provide a plant-specific TLAA or inspection/surveillance program to provide assurances that the capability of the prestressed concrete girders will continue to meet their intended function(s) during the period of extended operation.

In its response dated February 28, 2012, the applicant stated that the original design analysis for the fuel pool girders evaluated the loss of prestress caused by stress relaxation of the steel tendons and caused by creep and shrinkage of the concrete. The applicant also stated that since stress relaxation of the steel tendons is based upon a time-limited assumption, this analysis has been identified in the "updated" LRA as TLAA 4.6.10, and as such it requires evaluation for the period of extended operation. The applicant further stated that theTLAA was demonstrated to remain valid in accordance with 10 CFR 54.21(c)(1)(i) because the loss of prestress values used in the analysis are valid for over 60 years. In addition, the applicant stated that the fuel pool girders are included within the scope of the Structures Monitoring program B.2.1.35 and that the girders are visually examined once every 5 years for signs of concrete cracking or other degradation. Finally, the applicant stated that this program provides additional assurance that the fuel pool girders will continue to perform their intended function(s) during the period of extended operation.

The staff reviewed the applicant's response to RAI B.2.1.35-1 and confirmed that the revised LRA addresses the "Fuel Pool Girder Loss of Prestress," in section 4.6.10, and its UFSAR supplement, A.4.6.10, as a TLAA, which is reviewed in SER Section 4.6.10. For the visual examination of the prestress girders, the staff reviewed the applicant's response and confirmed that the fuel pool girders, as structural components, are included within the scope of the program. The staff also noted that girders are visually examined as recommended by ACI 349.3R-02 once every 5 years for signs of deterioration, rust stains, and concrete cracking. The staff also reviewed the LGS Units 1 and 2 UFSAR and noted that the spent fuel pool girders have multi-layer protection. On the pool side, a metallic liner that requires compliance with the requirements of 10 CFR 50, Appendix B (UFSAR Table 3.2-1, "LGS Design Criteria Summary"), keeps the water from direct contact with the concrete structure and its reinforcement. A free gravity leakage collection system assures expedient detection of leaks and further inhibits corrosion formation on tendons and reinforcement. The pool structure is made from dense concrete having compressive strength of 5,000 psi (UFSAR 3.8.6.1.2.2, "Concrete Mix Proportions") which is the desired strength of concrete to minimize crack widths thereby limiting water access to the reinforcement per ACI 201, "Guide to Durable Concrete," referenced by ACI 318, "Building Code Requirements for Structural Concrete," which is the code of record used in the pool construction (UFSAR 3.8.4.4, "Design and Analysis Procedures"). Cementitious grout assures the sealing of the tendons. All of these layers of protection enhance structural durability of the girders and have also been recognized to enhance structural performance, as articulated in 2002 VSL International report, "Grouting of Post-Tensioning Tendons." The staff finds the applicants response acceptable because the fuel pool girders are within the scope of the Structures Monitoring program and visually examined once every 5 years for signs of concrete cracking or other degradation, which is consistent with the recommendations in GALL Report AMP XI.S6. The staff's concern described in RAI B.2.1.35-01 is resolved.

The staff also reviewed the portions of the "scope of program," "preventative actions," "parameters monitored or measured," "detection of aging effects," 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.

Enhancement 1. LRA Section B.2.1.35 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the following structures will be added to the Structures Monitoring program: admin building warehouse, fuel oil pumphouse, SW pipe tunnel, and yard structures (auxiliary fire water storage tank foundation, backup fire pump house and foundation, well pump #3 enclosure and foundation, railroad bridge, manholes 001 and 002, fuel oil storage tank dike, transformer foundations and dikes). The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S6 and finds it acceptable because, when it is implemented, it will add structures to the Structures Monitoring program that are included in the scope of license renewal.

Enhancement 2. LRA Section B.2.1.35 states an enhancement to the "scope of program" program element. In this enhancement, the applicant stated that the following components and commodities will be added to the Structures Monitoring program: pipe, electrical, and equipment component supports; pipe whip restraints and jet impingement shields; panels, racks, and other enclosures; sliding surfaces; sump and pool liners; electrical duct banks; tube racks; doors; penetration seals; blowout panels, and per LRA revision dated April 13, 2012, permanent drywell shielding and roof scuppers. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S6 and finds it acceptable because, when it is implemented, it will add components and commodities to the Structures Monitoring program that are included in the scope of license renewal.

Enhancement 3. LRA Section B.2.1.35 states an enhancement to the "scope of program," "parameters monitored or inspected," and "detection of aging affects" program elements. In this enhancement, the applicant stated that the groundwater chemistry will be monitored 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 the impact, if any, on below-grade concrete. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will be consistent with the recommendations of GALL Report AMP XI.S6, for the aging management of below-grade structures and components.

<u>Enhancement 4</u>. LRA Section B.2.1.35 states an enhancement to the "preventative actions" program element. In this enhancement, the applicant stated that guidance will be provided for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting; and storage conditions will be revised for high-strength bolts to include recommendations of the RCSC Specification for Structural Joints Using High-Strength Bolts, Section 2.0. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S6 and finds it acceptable because when implemented, the recommended preventative actions identified in the GALL Report AMP will be included consistent with the guidance in NUREG-1339, EPRI NP-5769, EPRI NP-5067, and EPRI TR-104213 to ensure structural bolting integrity.

<u>Enhancement 5</u>. LRA Section B.2.1.35 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement, the applicant stated that concrete will be monitored for areas of abrasion, erosion, and cavitation degradation, drummy areas that exceed the cover concrete thickness in depth, popouts and voids, scaling, and passive settlements and deflections. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will include the parameters monitored or inspected identified in industry codes, standards, and guidelines (i.e., ACI 349.3R and ANSI/American Society of Civil Engineers (ASCE) 11) as recommended in GALL Report AMP XI.S6. Furthermore, this enhancement will provide the background to support inspections for loss of material for reinforced concrete exposed to flowing water and for inspections of the concrete foundation of accessible and inaccessible areas of the cooling tower basin slab.

<u>Enhancement 6</u>. LRA Section B.2.1.35 states an enhancement to the "detection of aging affects" program element. In this enhancement, the applicant stated that inspections of structures will be performed at a frequency not to exceed 5 years. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will monitor all structures at a frequency not to exceed 5 years as noted in RG 1.160 (Revision 2), ACI 349.3R, and as recommended in GALL Report AMP XI.S6.

<u>Enhancement 7</u>. LRA Section B.2.1.35 states an enhancement to the "parameters monitored or inspected" and "detection of aging affects" program elements. In this enhancement, the applicant stated that inspections of the subdrainage sump pit internal concrete will be performed on a 5-year frequency as a leading indicator of the condition of the below-grade concrete exposed to ground water. The LRA further notes that the "parameters monitored or inspected" program element will be enhanced to require opportunistic inspections of structures in the event an excavation is performed that exposes normally inaccessible concrete, and that evaluation of the acceptability of inaccessible areas is required when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas. The staff reviewed this enhancement and finds it acceptable because when it is implemented, it will monitor the subdrainage sump pit internal concrete at a frequency not to exceed 5 consistent with the recommendations in GALL Report AMP XI.S6, and the condition of the subdrainage

sump pit internal concrete can serve as a guide for the condition of the below-grade concrete since it is exposed to similar ground water conditions.

Enhancement 8. LRA Section B.2.1.35 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that personnel performing inspections and evaluations will meet the qualifications specified in ACI 349.3R. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will incorporate recommendations provided in GALL Report AMP XI.S6.

Enhancement 9. LRA Section B.2.1.35 states an enhancement to the "detection of aging effects" and "acceptance criteria" program elements. In this enhancement, the applicant stated that elastomeric vibration elements and structural seals will be inspected for cracking, loss of material, and hardening; visual inspections of elastomeric vibration elements are to be supplemented by manipulation to detect hardening when vibration isolation function is suspect. It is further noted in the LRA that the elastomeric vibration isolation elements are acceptable if loss of material, cracking, and hardening will not result in loss of sealing or loss of isolation function, and there has been no loss of material caused by corrosion or wear. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds them acceptable because when it is implemented, the enhancements will incorporate recommendations provided in GALL Report AMP XI.S6.

Enhancement 10. LRA Section B.2.1.35 states an enhancement to the "detection of aging effects" and "acceptance criteria" program elements. In this enhancement, the applicant stated that sliding surfaces will be monitored to detect significant loss of material caused by wear, corrosion, debris, or dirt that could result in lock-up or reduced movement. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds them acceptable because when it is implemented, the enhancements will incorporate recommendations provided in GALL Report AMP XI.S6.

Enhancement 11. LRA Section B.2.1.35 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that opportunistic inspections will be performed of below-grade portions of in-scope structures in the event excavation exposes normally inaccessible below-grade concrete. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will allow for opportunistic inspections of excavated normally inaccessible below-grade concrete structures and of inaccessible concrete if accessible concrete indicates degradation or the potential for degradation in inaccessible areas. This enhancement when incorporated will implement recommendations in the GALL Report AMP for aging management of below-grade concrete structures and components.

Enhancement 12. LRA Section B.2.1.35 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that acceptance criteria noted in ACI 349.3R will be included. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it will incorporate recommendations in the GALL Report AMP XI.S6 that acceptance criteria be in compliance with those identified in ACI 349.3R.

Enhancement 13. LRA Section B.2.1.35 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that loose bolts and nuts and high-strength bolts are not acceptable unless accepted by engineering evaluations. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S6 and finds it acceptable because when it is implemented, it incorporates the recommendations in GALL Report AMP XI.S6.

Based on its audit, and review of the applicant's response to RAI B.2.1.35-01 of the Structures Monitoring program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S6. In addition, the staff reviewed the enhancements associated with "scope of program," "preventative actions," "parameters monitored or measured," "detection of aging effects," 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.2.1.35 summarizes operating experience related to the Structures Monitoring program. Operating experience is reviewed from external and internal (also referred to as in-house) sources. External operating experience may include such things as INPO documents (e.g., significant operating experience reports (SOERs), significant event reports, significant event notifications (SENs), etc.), NRC documents (e.g., GLs, licensee event reports (LERs), INs, etc.), and other documents (e.g., 10 CFR Part 21 Reports, nuclear event reports (NERs), etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program notebooks, self-assessments, and in the 10 CFR Part 50, Appendix B CAP. Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that aging effects and mechanisms are being adequately addressed through inspections and the CAP with appropriate actions taken, and resolutions sought, when issues are identified that could affect structures' intended function(s). Followup inspections are performed on certain conditions at an increased frequency to ensure that subsequent changes will be identified and evaluated before there is an impact on the intended function of a structure. In addition, the applicant performs self-assessments and uses the results of the assessments to enhance the program.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During the audit the staff discussed with the applicant the intermittent leakage from the SFP. The staff noted that the leakage is discussed both in the LRA and in the Structures Monitoring program basis document. In the description of the leakage, the staff noted that the "E" drain line connected to the LGS Unit 2 SFP liner leak chase channels has been leaking about 10 ounces of SFP water per day since 1991. The staff expressed its concern to the applicant that the leak chase channels may be blocked resulting in the limited leakage. The applicant stated that sampling confirmed the leakage to be from the pool but it does not endanger the SFP makeup capability, as it remains small and unchanging. The applicant also stated that all eight valves of the leak chase system are opened daily to monitor the leakage. The applicant further stated that in October of 2010, they confirmed through nitrogen pressurization that there is flow through each of the leak chase lines and that when significant deviations of monthly measurements of leakage volume are noted they are entered into the CAP. The applicant also stated that visual examinations of accessible concrete surfaces based on the inspection procedures of the Structures Monitoring program have indicated that there is no external evidence of leakage on the pool walls and floor, assuring both the integrity of the structure and containment of leakage within the leak chase channels. The staff finds the applicant's response acceptable because (1) the valves of the leak chase system are opened daily to monitor for leakage, (2) flow has been confirmed to be contained within the leak chase lines (3) monthly measurements of leakage volume are made followed by visual examinations of accessible concrete surfaces under the Structure's Monitoring program, and (4) when significant deviations are observed, they are addressed through the CAP.

During its review the staff identified operating experience for which it determined the need for additional clarification, which resulted in the issuance of an RAI as discussed below.

The staff noted that the turbine building operating floor consists of the turbine pedestal and concrete slab on steel beams in all other floor areas. The ends of the steel beams adjacent to the turbine pedestal are supported by concrete ledges of the turbine pedestal. The other ends of the beams are supported by steel girders. The beam seat assemblies supported by the turbine pedestal consist of sliding surface plates, backup plates, and elastomeric pads. A walkdown by the applicant found that the beam ends supported by the turbine pedestal had settled approximately 0.5 inches as a result of deterioration/melting of the elastomeric pads. This condition was observed at almost all locations around the entire turbine pedestal expansion joint of both LGS Units 1 and 2. It was unclear to the staff if the turbine building operating floor and structure could still meet its intended functions and that the resulting change in alignment does not impact attachments or supports. By letter dated January 30, 2012, the staff issued RAI 2.1.35-2 requesting that the applicant provide the assessment demonstrating that the turbine building operating floor and structure can still perform its intended functions (e.g., supporting loads from the operating floor) and that the resulting change in alignment does not impact attachments or supports (e.g., pipe support anchor for the main steam line attached to a beam web does not induce stress into the pipe).

In its response dated February 28, 2012, the applicant confirmed that the change in alignment of the turbine enclosure operating floor and structure was caused by degraded/melted elastomeric pads, included as part of the sliding bearing assemblies located below the turbine operating deck floor beams. The applicant stated that the "comparatively small change in alignment" does not affect the load bearing capacity of the floor nor does it impact any turbine attachments or related supports (e. g., pipe support anchor for the main turbine sealing steam line attached to a beam web). The applicant further stated that they have evaluated the degraded elastomeric pads through the CAP and concluded that their current state does not affect the structural integrity of the turbine enclosure. A further assessment of this condition indicated that the degraded urethane elastomeric bearing pads between the beam end bearing plates and the concrete ledge resulted in a rotational change in alignment of the beams caused by 1/2-inch downward displacement at one end. The applicant also stated that there were no significant adverse structural effects on the operating concrete floor, beam structure, and turbine pedestal. The applicant stated that the elastomer was not considered in the design to dampen any floor vibrations and that the massive freestanding reinforced concrete turbine-generator pedestals are founded on rock at the same level as the basemat for the turbine enclosure. The applicant further stated that there are no adverse structural effects, significant vibration, or visible distress from vibration on the turbine-generator pedestal concrete or on the adjacent turbine operating floor and steel beams, which are periodically monitored by the Structures Monitoring program.

The applicant further stated that although additional investigation caused by misalignment, settlement, or rotation may be pursued through the CAP given the inherent flexibility of the 3-inch diameter main turbine steam seal leakoff piping, the induced secondary stresses would not be significant. The applicant also stated that there is no impact on safety-related piping and supports in the turbine enclosure. The applicant also stated that the safety-related portion of main steam piping supported from structural steel that is not affected by the displacement created by degraded elastomeric pads extends from the reactor enclosure wall penetration to the main turbine stop valves. The applicant further stated that the remainder of the main steam supply piping to the main turbine is of large diameter designed with a support system to accommodate large thermal movements.
The applicant also stated that the support system of the piping between the main turbine stop valves and main turbine is composed of variable supports with a comparatively large distance between supports such that the settlement of 0.5 inches at the end of the turbine pedestal has little impact on design loads and thermal displacements. The applicant also stated that the main turbine steam supply piping to the low-pressure turbines is supported from the turbine pedestal such that loads on the low-pressure turbine nozzles are unaffected by the degraded elastomeric pads and that piping supported from the structural steel affected by the degraded elastomeric pads is conventional piping, i. e. nonsafety-related and nonseismic. The applicant further stated that the installation tolerances for these piping systems are greater than the maximum displacement caused by the degraded pads. The applicant also stated that although the displacement is the greatest at the end of the beams supported by the turbine pedestal, the displacement is reduced as a function of distance from the turbine pedestal and therefore, no significant impact is expected on these piping systems. The applicant also stated that there have been no leaks or cracks in piping observed in the affected piping systems that are attributed to the alignment change associated with the elastomeric pad degradation.

The staff reviewed the applicant's response and noted that the LRA assigns in Table 3.5.1, "Summary of Aging Management Evaluations for Structures and Component Supports," item 3.5.1-72 (seals; gasket; moisture barriers – caulking, flashing, and other sealants) and the Structures Monitoring program to manage loss of sealing caused by deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants) of structures. The staff also noted an assignment report states that the elastomeric pads have degraded/melted, leading to a settlement of the steel beams by 0.5 inch. The staff also noted that the elastomeric pads are subject to loads and are part of the sliding bearing assemblies located below the turbine operating deck floor beams and, according to the LRA, permit the release of lateral forces. The staff further noted that Enhancement 9 to the Structures Monitoring program addresses inspection of elastomeric vibration isolation elements and structural seals for cracking, loss of material and hardening. Furthermore, the staff noted that enhancement 10 specifically addresses monitoring of accessible sliding surfaces. According to the RAI response the applicant continues to monitor the aging effects of the degraded elastomeric pad(s) by claiming AMR item consistency in Table 3.5.2-16, "Turbine Enclosure Summary of Aging Management Evaluation."

The staff finds the applicant's response acceptable because the enhanced Structures Monitoring program will monitor accessible sliding surfaces and has entered the degraded elastomeric pads in its CAP where the initial assessment of this condition is to be further evaluated. The staff's concern described in RAI B.2.1.35-2 is resolved.

Based on its audit, review of the application, and review of the applicant's responses to RAI B.2.1.35-2, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA A.2.1.35 provides the UFSAR supplement for the Structures Monitoring program, as revised by letter dated April 13, 2012. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 35) to enhance the Structures Monitoring program as described above, before entering 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 Structures Monitoring program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancements and confirmed that their implementation will make the AMP adequate to manage the applicable aging effects and the UFSAR supplement contained Commitment No. 35 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.18 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants

Summary of Technical Information in the Application. LRA Section B.2.1.36 describes the existing RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program as consistent, with enhancements, with GALL Report AMP XI.S7, "RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants. The program monitors the condition of the spray pond and pumphouse and the yard facility dikes (around the CST storage tank) structural components and commodities. The LRA states that the AMP addresses reinforced concrete, steel (screens, frames and miscellaneous steel) members and components, and earthen water-control structures (embankments and dikes) exposed to uncontrolled indoor air, outdoor air, raw water, standing water, flowing water, ground water, and soil to manage loss of material, loss of preload, cracking, loss of bond, loss of material (spalling, scaling) and cracking, increase in porosity and permeability, loss of strength, or loss of form. The program addresses age-related deterioration, degradation because of extreme environmental conditions, and the effects of natural phenomena that may affect the safety function of the water-control structures. The LRA also states that elements of the program are designed to detect degradation through inspections and evaluations and take corrective action to prevent a loss of intended function. The LRA further states that the AMP and monitoring of water-control structures is based on the guidance provided in NRC RG 1.127and ACI 349.3R-02.

Staff Evaluation. During its audit, 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.S7.

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.

Enhancement 1. LRA Section B.2.1.36 states an enhancement to the "preventive actions," "parameters monitored or inspected," and "acceptance criteria" program elements. In this enhancement, the applicant stated that inspection of structural bolting integrity will be required to identify loss of material and loosening of bolts. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, it will ensure that bolting in contact with raw water and outdoor air associated with the spray pond pump house and yard facility dikes around the condensate storage tank (CST) is inspected on both a routine and a condition-driven frequency. Also, recommended preventative actions, as identified in the relevant GALL Report AMPs, will be included consistent with the referenced NUREG-1339, EPRI NP-5769, EPRI NP-5067, and EPRI TR-104213 documents to ensure structural bolting integrity.

Enhancement 2. LRA Section B.2.1.36 states an enhancement to the "parameters monitored or inspected" program element. In this enhancement the applicant stated that monitoring is required for aging effects of increased porosity and permeability of concrete structures and loss of material for steel components. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, it will include GALL Report AMP recommended guidelines for parameters monitored or inspected identified in ACI 349.3R and ACI 201.1.

Enhancement 3. LRA Section B.2.1.36 states an enhancement to the "parameters monitored or inspected" program element. This enhancement will require the proper functioning of the dike drainage system. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, it will include the recommended guidelines for proper functioning of drainage systems of the GALL Report AMP.

Enhancement 4. LRA Section B.2.1.36 states an enhancement to the "detection of aging effects" program element. In this enhancement the applicant stated that increased inspection frequency is required if the extent of 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. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, it will incorporate recommendations in GALL Report AMP.

Enhancement 5. LRA Section B.2.1.36 states an enhancement to the "detection of aging effects" program element. In this enhancement the applicant stated that evaluation of the acceptability of inaccessible areas of concrete will be required when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, and examination of exposed portions of below-grade concrete is required when excavated for any reason. The staff reviewed this enhancement against the corresponding program elements in the GALL Report XI.S7 and finds it acceptable because when it is implemented, it will incorporate recommendations in the GALL Report AMP for aging management of below-grade structures and structural components.

Enhancement 6. LRA Section B.2.1.36 states an enhancement to the "detection of aging effects" program element. In this enhancement the applicant stated that raw water chemistry will be monitored at least every 5 years for pH, chlorides, and sulfates, and that it will confirm that the raw water remains nonaggressive, and when results exceed criteria an evaluation of the impact on submerged concrete will be required. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, it will include recommendations in the GALL Report AMP for aging management of below-grade concrete structures and structural components.

Enhancement 7. LRA Section B.2.1.36 states an enhancement to the "detection of aging effects" program element. In this enhancement the applicant stated that visual examinations of the spray pond and pumphouse submerged wetwell concrete will be required during maintenance activities and if significant degradation is identified a plant-specific AMP should be implemented to manage concrete aging during the period of extended operation. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will require visual inspections of the spray pond and pumphouse submerged wetwell concrete for signs of degradation consistent with recommendations in the GALL Report AMP.

Enhancement 8. LRA Section B.2.1.36 states an enhancement to the "monitoring and trending" program element. In this enhancement, the applicant stated that active cracks in structural concrete shall be documented and trended until the condition is no longer occurring or until a corrective action is implemented. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because, when it is implemented, it will be consistent with the recommendations in the GALL Report AMP for trending of changes of a degraded condition from previous inspections until it is evident that the change is no longer occurring or until corrective actions are implemented.

Enhancement 9. LRA Section B.2.1.36 states an enhancement to the "acceptance criteria" program element. In this enhancement, the applicant stated that acceptance and evaluation of structural concrete be based on quantitative criteria of Chapter 5 of ACI 349.3R. The staff reviewed this enhancement against the corresponding program element in GALL AMP Report XI.S7 and finds it acceptable because when it is implemented, it will comply with recommendations in the GALL Report AMP that acceptance criteria be in accordance with criteria identified in ACI 349.3R.

Enhancement 10. LRA Section B.2.1.36 states an enhancement to the "preventive actions" program element. In this enhancement the applicant stated that guidance will be provided for proper specification of bolting material, lubricant and sealants, and installation torque or tension to prevent or mitigate degradation and failure of structural bolting. The staff reviewed this enhancement against the corresponding program element in GALL Report AMP XI.S7 and finds it acceptable because when it is implemented, recommended preventative actions will be included consistent with NUREG-1339, EPRI NP-5769, EPRI NP-5067, and EPRI TR-104213 guidance to ensure structural bolting integrity.

Based on its audit of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S7. In addition, the staff reviewed the enhancements 1-10 associated with the "preventive actions," "parameters monitored or inspected," "detection of aging effects," "monitoring and trending," and "acceptance criteria" program elements and finds them acceptable as discussed above.

Operating Experience. LRA Section B.2.1.36 summarizes operating experience related to RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants program. Operating experience is reviewed from external and internal (also referred to as in-house) sources. External operating experience may include such things as Institute of Nuclear Power Operations (INPO) documents (e.g., SOERs, significant event reports, SENs, etc.), NRC documents and the applicant's responses (e.g., GLs, LERs, INs, etc.) where appropriate, and other documents (e.g., 10 CFR Part 21 Reports, NERs, etc.). Internal operating experience may include such things as event investigations, trending reports, and lessons learned from in-house events as captured in program documentation, self-assessments, and in the 10 CFR Part 50, Appendix B, CAP.

Demonstration that the effects of aging are effectively managed is achieved through objective evidence that shows that aging effects and mechanisms are being adequately managed. For example, the program-basis documentation indicated that in 2009 the results of the annual maintenance activity for measuring the spray pond silt depth through ultrasonic measurements indicated an increase in the rate of deposits. The monitoring frequency then was increased, based on the increasing trend of silt build-up, from once a year, to once every 6 months. The expected silt depth at the next measurement is projected, based on the deposition rate, to ensure that silt will not exceed acceptable levels. The program basis documentation also noted that as part of the preventative maintenance program the spray pond and pumphouse submerged wetwell concrete are visually inspected using criteria and personnel qualifications meeting the requirements of ACI 349.3R. The LRA discusses the applicant's approach to a removal of vegetative growth near the spray pond and pumphouse following a 2009 periodic inspection of these structures. An issue report was initiated and the vegetation was removed. The LGS operating experience indicates that periodic inspections and walkdowns are routinely performed to identify conditions that could affect the intended function of these water-control structures. Conditions requiring corrective actions are identified and preventative maintenance is performed and implemented so that the water-control structures continue to maintain their intended functions(s).

Based on its audit and review of the application the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.36 provides the UFSAR supplement for RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contains a commitment (Commitment No. 36) to enhance the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program as described above.

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 RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. 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. 36 to implement the enhancements before the period of extended operation. 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).

3.0.3.2.19 Protective Coating Monitoring and Maintenance Program

Summary of Technical Information in the Application. LRA Section B.2.1.37 describes the existing Protective Coating Monitoring and Maintenance Program as consistent, with an enhancement, to GALL Report AMP XI.S8, "Protective Coating Monitoring and Maintenance Program." The LRA states that the coatings program is a condition monitoring program that provides aging management of Service Level 1 coatings inside the LGS primary containment in indoor air and treated water environments. It further states that proper maintenance of the Service Level 1 coating ensures that coating degradation will not impact the operability of the ECCSs. The applicant also stated that Protective Coating Monitoring and Maintenance program provides for coating system visual inspection, assessment, and repair for any condition that adversely affects the ability of Service Level 1 coatings to function as intended.

The applicant stated that Service Level 1 coatings are not credited for managing the effects of corrosion for the carbon steel containment liners and components at LGS Units 1 and 2. The applicant indicated that this program ensures that the Service Level 1 coatings maintain adhesion so as to not affect the intended function of the ECCS suction strainers. In addition, the applicant stated that this program provides controls over the amount of unqualified coating, which is defined as coating inside the primary containment that has not passed the required laboratory testing, including irradiation and simulated DBA conditions. Furthermore, the applicant stated that the quantity of unqualified coating is controlled to ensure that the amount of unqualified coating in the primary containment is kept within acceptable design limits.

Staff Evaluation. During its audit, 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 element of GALL Report AMP XI.S8.

For the "scope of program," "detection of aging effects," and "monitoring and trending" program elements, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

The "scope of program," "detection of aging effects," and "monitoring and trending" program elements in GALL Report AMP XI.S8 recommends using ASTM D 5163, in as much as it defines the inspection frequency to be each refueling outage or during other major maintenance outages, as needed. However, during its audit, the staff found that the Protective Coating Monitoring and Maintenance program does not address inspection techniques or the frequency for inspection of the coating in the immersed region of the suppression pool. By letter dated January 30, 2012, the staff issued RAI B.2.1.37-1 requesting the applicant to provide the inspection technique used and frequency and scope of inspection for the Service Level 1 immersed coating in the suppression pool.

In its response letter, dated February 28, 2012, the applicant stated that the inspection frequency of Service Level 1 immersed coating in the suppression pool is consistent with ASTM D 5163-08 and ASME Code, Section XI, Subsection IWE for containment inservice inspection. The applicant further stated that the wetted surfaces of the suppression pool submerged areas had a 100 percent inspection completed in each 10-year ASME Code ISI interval. In addition, the applicant stated that consistent with GALL Report AMP XI.S8 element 4 and ASTM D 5163-08, paragraph 10.1, coating inspections will be by visual inspection techniques.

In its letter, dated September 12, 2012, responding to the SER with Open Items, the applicant provided additional information on the inspection frequency of the suppression pool. The applicant stated that an ASME IWE examination will be conducted each inservice inspection period (i.e., 3 times in 10 years) of 100 percent of the accessible submerged liner surface of the suppression pool. The staff finds the method of inspection and frequency acceptable since it is consistent with ASTM D 5163-08.

The staff's review of the ASME Code Section XI, Subsection IWE program is documented in SER Section 3.0.3.2.13. As discussed in SER Section 3.0.3.2.13, the inspection of coatings in the suppression pool is included as part of ASME Code Section XI, Subsection IWE program. For further clarification on how the applicant will manage the degraded areas of the suppression pool, refer to SER Section 3.0.3.2.13. The staff's concern described in RAI B.2.1.37 is resolved. The staff also reviewed the portions of the "detection of aging effects" program element associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B.2.1.37 states an enhancement to the "detection of aging effects" program element. In this enhancement, the applicant stated that LGS will create the position of Nuclear Coatings Specialist qualified to ASTM D 7108. The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP XI.S8 and finds it acceptable because when it is implemented, it will make the program consistent with the recommendations of GALL Report AMP XI.S8.

Based on its audit of the Protective Coating Monitoring and Maintenance program, and review of the applicant's responses to RAI B.2.1.37-1, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP XI.S8. In addition, the staff reviewed the enhancement associated with the "detection of aging effects" program element and finds that when implemented it will make the AMP adequate to manage the applicable aging effects.

Operating Experience. LRA Section B.2.1.37 summarizes operating experience related to the Protective Coating Monitoring and Maintenance program.

The applicant provided the following for operating experience:

The applicant stated that Service Level 1 coating inspections in the submerged region of the LGS Unit 1 suppression pool were performed during refueling outages in 2004, 2006, and 2010. It was stated that the inspection covered 100 percent of the accessible Service Level 1 coatings on the suppression pool liner, downcomers, and columns. It was indicated that four areas of corrosion were preemptively spot recoated. The applicant completed an apparent cause evaluation as part of the CAP. Improved plans for monitoring coating and containment liner corrosion for both LGS Units 1 and 2 have been developed and are implemented through the ASME Code Section XI ISI program. The applicant stated that these actions will ensure that areas exhibiting coating defects and deficiencies are evaluated, impacts on liner degradation are determined, and recoating plans are developed.

The applicant stated that a design change package approved the permanent removal of the reactor recirculation pump motor hoists from the Unit 1, primary containment. It was determined that removal of the hoists would reduce the amount of unqualified coating in the primary containment and that the design analysis that evaluates the containment unqualified coatings inventory against ECCS suction strainer capacity was affected. It was reported that the design analysis was revised and the total weight determined in the unqualified coatings inventory of the calculation was reduced caused by the elimination of the hoists.
The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program.

During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, and review of the applicant's response to RAI B.2.1.37-1, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience, operating experience related to the applicant's program that demonstrates it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.2.1.37 provides the UFSAR supplement for the Protective Coating Monitoring and Maintenance program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 3.0-1. The staff also noted that the UFSAR supplement contained a commitment (Commitment No. 37) to enhance the program by creating the position of Nuclear Coatings Specialist qualified to ASTM standard D 7108. It was stated that the enhancement will be implemented 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 Protective Coating Monitoring and Maintenance program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR supplement contained Commitment No. 37 to implement the enhancement before the period of extended operation. 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).

3.0.3.2.20 Fatigue Monitoring

Summary of Technical Information in the Application. LRA Section B.3.1.1 describes the existing Fatigue Monitoring program as consistent, with an enhancement, with GALL Report AMP X.M1, "Fatigue Monitoring." The LRA states that the program monitors and tracks the number of critical thermal, pressure, and seismic transients and requires comparison of the actual event parameters (pressure, temperature, or flow rate changes) to the applicable design transient definitions to assure the actual transients are bounded by the applicable design transients. In addition, the program includes counting the operational transients to ensure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting fatigue analysis, including environmental fatigue analyses. If a cycle limit is approached, corrective actions are triggered to prevent exceeding the limit.

The LRA also states that the effect of the reactor coolant environment on RCPB component fatigue life has been determined by performing environmental fatigue analyses for a sample of critical locations selected using NUREG/CR-6260 guidance and performing additional environmental fatigue analyses for limiting locations within each RCPB system and each RPV component with a ASME Code, Class 1 fatigue analysis. The applicant's environmentally adjusted fatigue usage factors (CUF_{en}) were computed in accordance with NUREG/CR-6909 for all materials.

Staff Evaluation. During its audit, 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 X.M1.

For the "monitoring and trending" program element, the staff determined the need for additional information, which resulted in the issuance of an RAI, as discussed below.

LRA Section 4.3.1 states that each transient projection was trended to determine if recent rates of occurrence could be higher than the overall average rate of occurrence and the trending shows that recent transient occurrence rates are bounded by the average occurrence rates. The TLAA evaluations in LRA Sections 4.3.5, 4.6.5 and 4.6.7 are dispositioned in accordance with 10 CFR 54.21(c)(1)(i), the analysis remains valid for the period of extended operation, and rely on the 60-year projections that were discussed in LRA Section 4.3.1. The "monitoring and trending" program element of GALL Report AMP X.M1 recommends that trending is assessed to ensure that the fatigue usage factor remains below the design limit during the period of extended operation. During its audit, the staff found that the Fatigue Monitoring program will continue to monitor and track transient cycles against the cycle limits throughout the period of extended operation to ensure that the 60-year projections are valid. However, since the TLAAs described above rely on the 60-year projections that the Fatigue Monitoring program is assuring will remain valid throughout the period of extended operation, it is not clear to the staff if the validity of these TLAAs will be confirmed if the program determines that a transient cycle count has reached a cycle limit.

By letter dated November 18, 2011, the staff issued RAI B.3.1-1, requesting the applicant to confirm that the implementing procedures or corrective actions of the Fatigue Monitoring program ensures that the TLAAs, that rely on 60-year projections and are dispositioned in accordance with 10 CFR 54.21(c)(1)(i), will be evaluated if a cycle count reaches an allowable cycle limit.

In its response dated, December 7, 2011, the applicant stated that each of the components with fatigue TLAAs, dispositioned in accordance with 10 CFR 54.21(c)(1)(i), are within the scope of the Fatigue Monitoring program, including the RVI (LRA Section 4.3.4), High-Energy Line Break Analyses Based Upon Fatigue (LRA Section 4.3.5), the Jet Pump Auxiliary Spring Wedge Assembly (LRA Section 4.6.5), and the Refueling Bellows (LRA Section 4.6.7). The applicant clarified that these fatigue analyses are based on the same set of design transients monitored and trended in the Fatigue Monitoring program. The staff noted that if the cumulative number of cycles for any of these transients exceeds 80 percent of the allowable cycle limit, the program's implementing procedures trigger corrective actions to prevent exceeding the cycle count limit. The applicant stated that these procedures require the Fatigue Monitoring Engineer to initiate an action in the CAP to perform an engineering evaluation of the condition and determine the corrective action, which include reanalysis of the component to demonstrate that the design ASME Code limit will not be exceeded before or during the period of extended operation; repair of the component; replacement of the component, or other methods approved by the NRC.

In addition, the applicant identified a typographical error LRA Section B.3.1.1 regarding the program elements that affected changing "corrective action (element 6)" to "acceptance criteria (element 6)."

The staff finds the applicant's response acceptable because the applicant confirmed that the implementing procedures for its Fatigue Monitoring program will ensure the validity of the fatigue TLAAs described above if a transient cycle count reaches 80 percent of an allowable cycle limit. Therefore, the staff finds that the applicant continually ensures that the results from its 60-year projections used to disposition these fatigue TLAAs in accordance with 10 CFR 54.21(c)(1)(i), will remain valid during the period of extended operation; otherwise, corrective actions will be taken. The staff's concern described in RAI B.3.1-1 is resolved.

The staff also reviewed the portions of the "preventive actions," "parameters monitored or inspected," and "acceptance criteria" program elements associated with an enhancement to determine whether the program will be adequate to manage the aging effects for which it is credited. The staff's evaluation of this enhancement follows.

Enhancement. LRA Section B.3.1.1, as amended by letter dated December 7, 2011, states an enhancement to the "preventive actions," "parameters monitored or inspected" and "acceptance criteria" program elements. In this enhancement, the applicant stated that the program will be enhanced to monitor additional plant transients that are significant contributors to fatigue usage and impose administrative transient cycle limits corresponding to the limiting numbers of cycles analyzed in the environmental fatigue calculations.

The staff noted that the "preventive actions" program element states the program prevents the fatigue analyses from becoming invalid by assuring that the fatigue usage resulting from actual operational transients does not exceed the ASME Code design limit of 1.0, including environmental effects where applicable. The staff noted that the "parameters monitored or inspected" program element states the program monitors all plant design transients that cause cyclic strains, which are significant contributors to the fatigue usage factor and that the number of occurrences of the plant transients that cause significant fatigue usage for each component is to be monitored. The staff noted that the "acceptance criteria" program element states the acceptance criterion is maintaining the cumulative fatigue usage below the design limit through the period of extended operation, with consideration of the reactor water environmental fatigue effects.

When enhanced, the applicant's program will monitor those additional transients not already monitored by the existing program that are significant contributors to fatigue usage (i.e., those transients assumed in a fatigue analysis) and ensure that the fatigue analyses do not become invalid, including environmental effects where applicable. The staff finds this consistent with the "parameters monitored or inspected" program elements. As described in the applicant's letter dated December 7, 2011, the implementing procedures for its Fatigue Monitoring program includes an 80 percent action limit for cycle counts and is based on the limiting number of cycles used in the fatigue analyses. When enhanced, the applicant's program will impose administrative transient cycle limits corresponding to the limiting numbers of cycles analyzed in the environmental fatigue calculations. The staff noted that setting an 80 percent action limit that is based on the limiting number of cycles used in the design fatigue analyses or environmentally assisted fatigue analyses ensures the ASME Code design limit of 1.0 is not exceeded, consistent with the "acceptance criteria" program element. By managing those transients assumed in the design fatigue analyses and environmental fatigue calculations to an 80 percent action limit the applicant prevents the calculated CUF or CUF_{en} values from becoming invalid, which the staff finds consistent with the "preventive actions" program element.

The staff reviewed this enhancement against the corresponding program elements in GALL Report AMP X.M1 and finds it acceptable because when it is implemented, the applicant's program will be consistent with the recommendations of the GALL Report, as described above.

Based on its audit of the Fatigue Monitoring program, the staff finds that program elements 1-6 for which the applicant claimed consistency with the GALL Report are consistent with the corresponding program elements of GALL Report AMP X.M1. In addition, the staff reviewed the enhancement associated with the "preventive actions," "parameters monitored or inspected," and "acceptance criteria" program elements and finds that when implemented, it will make the AMP adequate to manage the applicable aging effects.

<u>Operating Experience</u>. LRA Section B.3.1.1 summarizes operating experience related to the Fatigue Monitoring program. LRA Section B.3.1.1 states that in 2009, the applicant identified inconsistencies in the cumulative cycle counts shown on the reactor vessel thermal transient monitoring data sheets prepared for LGS Units 1 and 2. The applicant clarified that the issues were historical and primarily associated with incorrect transferring of cumulative cycle count totals from one quarterly report to the next, resulting in discrepancies between the individual event occurrences and the cumulative cycle counts. The applicant revised its procedures to include improved human factors. The staff noted that the applicant's program demonstrates that it performs self-assessments to ensure that accurate cycles counts are maintained; otherwise, corrective actions are taken to ensure that design limits and cumulative cycle counts are within the design.

The staff reviewed operating experience information in the application and during the audit to determine whether the applicable aging effects, and industry and plant-specific operating experience were reviewed by the applicant. As discussed in the Audit Report, the staff conducted an independent search of the plant operating experience information to determine whether the applicant had adequately evaluated and incorporated operating experience related to this program. During its review, the staff found no operating experience to indicate that the applicant's program would not be effective in adequately managing aging effects during the period of extended operation.

Based on its audit and review of the application, the staff finds that the applicant has appropriately evaluated plant-specific and industry operating experience. Operating experience related to the applicant's program demonstrates that it can adequately manage the effects of aging on SSCs within the scope of the program, and that implementation of the program has resulted in the applicant taking corrective actions.

UFSAR Supplement. LRA Section A.3.1.1 provides the UFSAR supplement for the Fatigue Monitoring program. The staff reviewed this UFSAR supplement description of the program and noted that it is consistent with the recommended description in SRP-LR Table 4.3-2. The staff also noted that the UFSAR supplement included a commitment (Commitment No. 44) to enhance the existing Fatigue Monitoring program to 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 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 Fatigue Monitoring program, the staff determines that those program elements for which the applicant claimed consistency with the GALL Report are consistent. Also, the staff reviewed the enhancement and confirmed that its implementation will make the AMP adequate to manage the applicable aging effects and that the UFSAR supplement contains Commitment No. 44 to implement the enhancement before the period of extended operation. 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).

3.0.4 QA Program Attributes Integral to Aging Management Programs

As required by 10 CFR 54.21(a)(3), the applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended function(s) will be maintained consistent with the CLB for the period of extended operation. SRP-LR, Branch Technical Position (BTP) RLSB-1, "Aging Management Review – Generic," describes 10 elements of an acceptable AMP. Elements (7), (8), and (9) are associated with the QA activities of "corrective actions," "confirmation process," and "administrative controls." BTP RLSB-1 Table A.1-1, "Elements of an Aging Management Program for License Renewal," provides the following description of these program elements:

(1) "corrective actions" – "corrective actions," including root cause determination and prevention of recurrence, should be timely

(2) "confirmation process" – the "confirmation process" should ensure that preventive actions are adequate and that appropriate corrective actions are completed and effective

(3) "administrative controls" – "administrative controls" should provide for a formal review and approval process

BTP IQMB-1, "Quality Assurance for Aging Management Programs," notes that AMP aspects that affect the quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50 Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the applicant may use the existing 10 CFR Part 50 Appendix B QA Program to address the elements of "corrective actions," "confirmation process," and "administrative controls." BTP IQMB-1 provides the following guidance on the QA attributes of AMPs:

- safety-related SCs are subject to 10 CFR Part 50 Appendix B requirements that are adequate to address all quality-related aspects of an AMP consistent with the CLB of the facility for the period of extended operation
- for nonsafety-related SCs that are subject to an AMR, an applicant has an option to expand the scope of its 10 CFR Part 50 Appendix B program to include these SCs to address "corrective action," "confirmation process," and "administrative control" for aging management during the period of extended operation. In this case, the applicant should document such commitment in the UFSAR supplement in accordance with 10 CFR 54.21(d)

3.0.4.1 Summary of Technical Information in the Application

In LRA Appendix A, "Updated Final Safety Analysis Report Supplement," Section A.1.5, "Quality Assurance Program and Administrative Controls," and LRA, Appendix B, "Aging Management Programs," Section B.1.3, "Quality Assurance Program and Administrative Controls," the applicant described the elements of "corrective action," "confirmation process," and "administrative controls" that are applied to the AMPs for both safety-related (SR) and nonsafety-related components.

LRA Appendix A, Section A.1.5 states:

> The Quality Assurance Program [QAP] implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, "Quality Assurance For Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, and components (SSCs) that are subject to Aging Management Review (AMR).

LRA Appendix B, Section B.1.3 states:

> The Quality Assurance Program implements the requirements of 10 CFR 50, Appendix B, and is consistent with the summary in Appendix A.2, "Quality Assurance for Aging Management Programs (Branch Technical Position IQMB-1)" of NUREG-1800. The Quality Assurance Program includes the elements of corrective action, confirmation

process, and administrative controls, and is applicable to the safety-related and nonsafety-related systems, structures, components (SSCs), and commodity groups that are subject to an AMR.

3.0.4.2 Staff Evaluation

As required by 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effects of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. The SRP-LR, Branch Technical Position RLSB-1, "Aging Management Review - Generic," describes 10 attributes of an acceptable AMP. Three of these 10 attributes are associated with the QA activities of corrective action, confirmation process, and administrative controls. Table A.1-1, "Elements of an Aging Management Program for License Renewal," of Branch Technical Position RLSB-1 provides the following description of these quality attributes:

- Attribute No. 7 – "corrective actions," including root cause determination and prevention of recurrence, should be timely
- Attribute No. 8 – "confirmation process, which should ensure that preventive actions are adequate and that appropriate corrective actions have been completed and are effective
- Attribute No. 9 – "administrative controls," which should provide a formal review and approval process.

The SRP-LR, Branch Technical Position IQMB-1, "Quality Assurance for Aging Management Programs," states that those aspects of the AMP that affect quality of safety-related SSCs are subject to the QA requirements of 10 CFR Part 50, Appendix B. Additionally, for nonsafety-related SCs subject to an AMR, the applicant's existing 10 CFR Part 50, Appendix B, QAP may be used to address the elements of "corrective action," "confirmation process," and "administrative control." Branch Technical Position IQMB-1 provides the following guidance with regard to the QA attributes of AMPs:

> Safety-related SCs are subject to Appendix B to 10 CFR Part 50 requirements, which are adequate to address all quality related aspects of an AMP consistent with the CLB of the facility for the period of extended operation. For nonsafety-related SCs that are subject to an AMR for license renewal, an applicant has an option to expand the scope of its Appendix B to 10 CFR Part 50 program to include these SCs to address corrective action, confirmation process, and administrative control for aging management during the period of extended operation. In this case, the applicant should document such a commitment in the Final Safety Analysis Report supplement in accordance with 10 CFR 54.21(d).

The staff reviewed Appendix A, Section A.1.5, and LRA Appendix B, Section B.1.3, and the applicant's implementing procedures, which describe how the existing LGS QAP includes the QA-related elements ("corrective action," "confirmation process," and "administrative controls") for AMPs consistent with the staff's guidance described in Branch Technical Position IQMB-1. The staff also reviewed a sample of AMP program basis documents and confirmed that the AMPs implement the CAP, confirmation processes, and administrative controls as described in the LRA. Based on its review, the staff determined that the quality attributes presented in the AMP program basis documents and the associated AMPs are consistent with the staff's position regarding QA for aging management.

3.0.4.3 Conclusion

On the basis of the staff's evaluation of LRA Appendix A, Section A.1.5 and Appendix B, Section B.1.3, the AMP program basis documents the staff concluded that the QA attributes ("corrective action," "confirmation process," and "administrative control") of the applicant's AMPs are consistent with SRP-LR, Branch Technical Position RLSB-1.

3.0.5 Operating Experience for Aging Management Programs

3.0.5.1 Summary of Technical Information in Application

LRA Section B.1.4 describes the consideration of operating experience for AMPs. The LRA states that the description of each AMP contains a discussion of operating experience relevant to the program. This information was obtained through the review of in-house operating experience captured by the CAP, program self-assessments, program health reports, and through the review of industry operating experience. The applicant also states that operating experience was obtained through interviews with system engineers, program engineers, and other plant personnel. Plant-specific and industry operating experience were used for new programs, as applicable. In addition, the LRA states that, during the first 10 years of entering the period of extended operation, the owners of AMPs credited for license renewal will review plant-specific and industry operating experience to confirm the effectiveness of the AMPs and followup actions will be taken as appropriate to provide additional assurance that aging of SSCs within the scope of license renewal will be adequately managed throughout the period of extended operation.

3.0.5.2 Staff Evaluation

Pursuant to 10 CFR 54.21(a)(3), an applicant is required to demonstrate that the effect of aging on SCs subject to an AMR will be adequately managed so that their intended functions will be maintained consistent with the CLB for the period of extended operation. SRP-LR, Revision 2, Appendix A, describes 10 elements of an acceptable AMP. SRP-LR Section A.1.2.3.10 describes Element 10, "Operating Experience," as consisting of these three attributes:

(1) Consideration of future plant-specific and industry operating experience relating to aging management programs should be discussed. Reviews of operating experience by the applicant in the future may identify areas where aging management programs should be enhanced or new programs developed. An applicant should commit to a future review of plant-specific and industry operating experience to confirm the effectiveness of its aging management programs or indicate a need to develop new aging management programs. This information should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the structure and component intended function(s) will be maintained during the period of extended operation.

(2) Operating experience with existing programs should be discussed. The operating experience of AMPs that are existing programs, including past corrective actions resulting in program enhancements or additional programs, should be considered. A past failure would not necessarily invalidate an AMP because the feedback from operating experience should have resulted in appropriate program enhancements or new programs. This information can

show where an existing program has succeeded and where it has failed (if at all) in intercepting aging degradation in a timely manner. This information should provide objective evidence to support the conclusion that the effects of aging will be adequately managed so that the structure- and component-intended function(s) will be maintained during the period of extended operation.

(3) For new AMPs that have yet to be implemented at an applicant's facility, the programs have not yet generated any operating experience (OE). However, there may be other relevant plant-specific OE at the plant or generic OE in the industry that is relevant to the AMP's program elements even though the OE was not identified as a result of the implementation of the new program. Thus, for new programs, an applicant may need to consider the impact of relevant OE that results from the past implementation of its existing AMPs that are existing programs and the impact of relevant generic OE on developing the program elements. Therefore, operating experience applicable to new programs should be discussed. Additionally, an applicant should commit to a review of future plant-specific and industry operating experience for new programs to confirm its effectiveness.

SER Section 3.0.3 discusses the staff's review of the second and third attributes, which concern operating experience associated with existing and new programs, respectively. The below evaluation discusses the staff's review of the first attribute, which concerns the consideration of future operating experience and applies to both existing and new programs.

The staff reviewed LRA Sections B.1.4 and B.2.1.1 through B.2.1.43 to determine whether the applicant will implement adequate activities for the ongoing review of both plant-specific and industry operating experience to identify areas where the AMPs should be enhanced or new AMPs developed. Although LRA Section B.1.4 states that the applicant will review plant-specific and industry operating experience during the first 10 years of entering the period of extended operation to confirm the effectiveness of the AMPs and to determine appropriate followup actions, it is not clear how specifically, the applicant will use future operating experience to ensure that the AMPs will remain effective for managing the effects of aging during the period of extended operation.

By letter dated February 16, 2012, the staff issued RAI B.1.4-1 requesting that the applicant describe in detail the programmatic activities that will be used to continually identify aging issues, evaluate them, and, as necessary, enhance the AMPs or develop new AMPs. In the description of these activities, the staff also requested that the applicant specifically address the following:

- sources of plant-specific and industry operating experience information reviewed on an ongoing basis
- criteria for determining when operating experience concerns aging
- training of plant personnel for identifying age-related issues
- evaluation of operating experience to determine its potential impact on the plant aging management activities
- consideration of SCs, their materials, environments, aging effects, aging mechanisms, and AMPs in operating experience evaluations

- consideration of AMP inspections results
- records kept of operating experience evaluations
- process for the timely implementation of enhancements identified through operating experience evaluations
- administrative controls over the operating experience review activities

The applicant's response to RAI B1.4-1, in its letter dated March 13, 2012, provided further details on how it will review plant-specific and industry operating experience. In summary, the applicant stated that it will use its established, mature plant Operating Experience program and its CAP to evaluate and address degraded conditions including plant-specific and industry operating experience and to provide assurance of the effectiveness of AMPs and the development of new or enhanced AMPs when operating experience indicates that the current AMPs may not be fully effective. The applicant described how plant-specific operating experience is captured and processed through the CAP and stated that industry operating experience will be obtained from a number of sources, including the INPO website and NRC generic communications. The applicant also described the process and criteria used to identify and evaluate operating experience and stated that plant-specific operating experience will be reported to the industry. Training requirements for plant personnel responsible for screening, assigning, evaluating, and submitting plant-specific and industry operating experience is also described. Several enhancements to the Operating Experience program were identified and the applicant stated that these enhancements will be completed before entering the period of extended operation.

Subsequent to the receipt of the applicant's response to RAI B.1.4-1, the staff issued its final License Renewal Interim Staff Guidance (LR-ISG) 2011-05, "Ongoing Review of Operating Experience."

The staff evaluated the details of the applicant's description of the ongoing operating experience review activities with respect to the following framework set forth in LR-ISG-2011-05:

- consideration of operating experience in the 10 CFR Part 50, Appendix B, QA program
- sources of operating experience
- consideration of all incoming plant-specific and industry operating experience
- identification of operating experience related to aging
- information considered in operating experience evaluations
- consideration of AMP implementation results as operating experience
- training
- reporting operating experience to the industry
- implementation schedule

First, the staff evaluated how the applicant's 10 CFR Part 50, Appendix B, QA program will consider operating experience on age-related degradation and aging management. LRA Sections A.1.5 and B.1.3 state that the QA program implements the requirements of 10 CFR Part 50, Appendix B, and is applicable to safety-related and nonsafety-related SSCs subject to an AMR. The staff finds the QA program acceptable because the scope of the program includes nonsafety-related SSCs. This expanded scope of the QA program can incorporate operating experience related to aging degradation and aging management for all SSCs identified in the IPA.

Second, the staff evaluated the sources of operating experience reviewed by the applicant. LRA Section B.1.4 states that plant-specific operating experience comes from sources such as event investigations, trending reports, and lessons learned from in-house events, as captured in self-assessments and the CAP. The LRA also states that, under the CAP, issue reports are required to address actual or potential plant problems, including unexpected plant equipment degradation, damage, malfunction, or loss of function. Other plant-specific sources, as further described in the applicant's response to RAI B.1.4-1, include tests, inspections, plant walkdowns, and adverse results, which include adverse AMP-related inspection results. In addition, the response to RAI B.1.4-1 states that the applicant will enhance the CAP to include direction to include operating experience related to aging. The staff determined that the applicant's CAP is adequate to capture applicable sources of plant-specific operating experience because the CAP receives input from a broad scope of plant activities used to identify potential age-related issues. In addition, the applicant's enhancement will further ensure that the CAP will not preclude the capture and evaluation of operating experience related to aging, which is consistent with the guidance in LR-ISG-2011-05.

The response dated March 13, 2012, also provides examples of industry operating experience documents screened under the Operating Experience program for applicability to LGS. The applicant stated that these documents include Institute of Nuclear Power Operations (INPO) Event Reports, NRC Bulletins, GLs, INs, and Regulatory Issue Summaries, as well as topical reports and vendor correspondence. The applicant further stated that LR-ISG documents will be added to the scope of items that are screened. The staff finds acceptable the sources of industry operating experience considered by the applicant because the Operating Experience program prescribes review of operating experience from what the staff considers to be the primary providers of industry operating experience information (i.e., NRC, other nuclear power plants through INPO, and vendors). The NRC previously endorsed use of the INPO program as the mechanism for the central collection and screening of all events from both United States and foreign nuclear plants in GL 82-04, "Use of INPO SEE-IN Program," dated March 9, 1982.

Third, the staff evaluated the applicant's activities for screening of all incoming plant-specific and industry operating experience to determine whether it may involve age-related degradation or impacts to aging management activities. The applicant's response dated March 13, 2012, states the CAP and the Operating Experience program are used together to evaluate and address adverse plant-specific and industry operating experience including aging-related degradation. The applicant further stated that the existing Operating Experience program and operating experience coordinator training will be enhanced to ensure that both internal and external aging-related operating experience is properly reviewed and disseminated for evaluation by the appropriate plant or corporate personnel. The applicant also stated that identification coding will be established within the CAP and with communication at the industry level to identify and trend operating experience related to aging management. The staff finds acceptable the use of the CAP and the Operating Experience program to screen operating experience in this respect because both programs would not preclude the capture of plant-specific and industry operating experience related to aging.

Fourth, the staff evaluated the applicant's identification of plant-specific operating experience as related to aging in the CAP. The applicant's response dated March 13, 2012, stated identification coding will be established within the CAP database to identify operating experience concerning age-related degradation applicable to the plant. The applicant further stated that the coding will be used to address specific issues, assess the adequacy of existing AMPs, and to enhance them as necessary. In addition, the applicant stated that personnel will be required to periodically assess the performance of the AMPs and determine if AMP revisions or new AMPs are appropriate. The staff finds acceptable the applicant's process for identifying operating experience as related to aging because all operating experience items submitted into the CAP and Operating Experience program will be reviewed and identified as involving potential aging issues.

Fifth, the staff evaluated the information that the applicant will consider in the operating experience evaluations. The applicant's response dated March 13, 2012, states that operating experience evaluations relating to aging management will consider the following:

- SSCs that are similar or identical to those involved with the identified operating experience issue, to gain relevant lessons learned
- materials of construction, operating environment and aging effects associated with the identified aging issue so that lessons learned can be applied to susceptible SSCs in the scope of license renewal
- aging mechanisms associated with the operating experience to confirm that LGS has appropriate AMPs in place to manage aging that could be caused by these mechanisms.
- AMPs involved with this operating experience so that if the AMPs have been demonstrated to be ineffective, similar AMPs in place at LGS can be evaluated to determine if AMP changes are appropriate, or if a new AMP is needed
-

The response further states that an issue report will be initiated when plant-specific or industry vulnerabilities are determined. The applicant stated that plant-specific vulnerabilities determined by the evaluation will be processed and further evaluated through the CAP. An evaluation is also performed for an issue report initiated by industry operating experience. The response states that, if a deficient condition related to aging is identified by the evaluation, and applicable to SSCs within the scope of license renewal, the applicant will determine whether AMPs should be enhanced or new AMPs developed. The staff finds acceptable the information that will be considered in the applicant's operating experience evaluations because this information will involve potential aging issues and consideration of the fundamental components of an AMR, namely the potentially affected plant SSCs, materials, environments, aging effects, aging mechanisms, and AMPs. Consideration of this information in the operating experience reviews will facilitate the assessment of all potential impacts to the aging management activities.

Sixth, the staff evaluated the applicant's consideration of AMP implementation results as operating experience. The applicant's response dated March 13, 2012, states that the Exelon work management system records all results of AMP inspections, tests, analyses, etc. regardless of whether they meet the applicable acceptance criteria. The response further states that an issue report is initiated within the CAP for results that do not meet the acceptance criteria and appropriate corrective actions are taken. Corrective actions include correcting the specific condition, considering the extent of condition, and evaluating the adequacy of existing AMPs. The applicant stated that the evaluation will consider modification of existing AMPs or the development of new AMPs. The staff finds the applicant's consideration of the AMP inspection results acceptable because unsatisfactory results will be entered into the CAP, which is used to evaluate plant-specific operating experience. The staff also finds the applicant's response acceptable because data collected by the AMPs will be reviewed and revisions to the programs will be implemented as necessary, which will further help to ensure that the programs are effective.

Seventh, the staff evaluated the training of plant personnel responsible for implementing the AMPs and those personnel who may submit, screen, assign, evaluate, or otherwise process plant-specific and industry operating experience. The applicant's response dated March 13, 2012, states that the Operating Experience program has personnel that are assigned and trained in the functions of screening, assigning, evaluating, and submitting plant-specific and industry operating experience. The applicant further described the roles of four key personnel: (1) the Exelon Fleet Coordinator, who is central input for all operating experience for the Exelon fleet; (2) the LGS Site Operating Experience Program Coordinator, who is the operating experience champion and responsible for processing both internal fleet operating experience and outgoing operating experience notifications to the industry; (3) the Station Aging Management Coordinator (AMC), who will be the LGS lead for overseeing the effective implementation of activities related to license renewal and reviewing internal and external operating experience for lessons learned applicable to LGS and aging-related operating experience that should be shared with the industry; and (4) the LGS AMP owners for existing and new AMPs, who are involved with the development, review, and approval of the AMPs credited for aging management.

The applicant stated that the fleet and LGS Station Operating Experience Program Coordinator training will be updated to enhance the review, dissemination, and evaluation of internal and external age-related operating experience. The applicant further stated that the LGS AMC will be trained to be proficient in screening and evaluating age-related operating experience and AMP owners have received classroom training that includes component aging. The applicant also stated that training enhancements will be made periodically to include aging management information and that the Operating Experience program requires newly assigned personnel to complete training to effectively perform the job function. The staff finds acceptable the applicant's training of plant personnel because the primary personnel responsible for screening, assigning, evaluating, and submitting operating experience issues will receive training on aging-related topics. The staff also finds the applicant's training acceptable because it will be periodically updated and will be required for new personnel.

Eighth, the staff evaluated the reporting of LGS operating experience to the industry. The applicant's response dated March 13, 2012, states that the Operating Experience program will be enhanced to include guidance for reporting plant-specific operating experience related to aging to the industry. The applicant stated that this guidance will include the following:

- observation of aging-related degradation significantly beyond what was expected, based upon an existing AMP inspection frequency, methodology, etc.
- aging effects or mechanisms not previously seen or accounted for in the AMPs
- other significant changes required or being made to AMPs that may be of interest to the industry

Also, the applicant stated that the roles of the AMC and LGS Site Operating Experience Program Coordinator include determining and processing aging-related operating experience that will be shared with the industry. As previously described, the AMC will be trained in screening and evaluating operating experience concerning age-related degradation. The staff finds acceptable the applicant's guidelines for reporting internal operating experience to the industry because they address aging issues and because the identification of noteworthy operating experience will be from individuals with training on aging topics. This reporting of

operating experience to the industry is consistent with the NRC's endorsement of the INPO program in GL 82-04.
Ninth and last, the staff evaluated the implementation schedule for the operating experience review activities described by the applicant. The applicant's response dated March 13, 2012, describes enhancements to the Operating Experience program to provide assurance that age-related degradation operating experience will be considered to determine the effectiveness of AMPs and the need for enhancements or new AMPs. The applicant's response dated June 19, 2012, describes the timetable and basis for completion of the enhancements. The applicant stated that it plans to implement the enhancements within 2 years following the receipt of the renewed operating license, which will be approximately 9 years before the period of extended operation. The applicant also stated that the current Operating Experience program and CAP have been shown to be effective in identifying and addressing age-related degradation. In addition, the applicant stated that these enhancements will be initiated across the Exelon Nuclear plant fleet and will require collaboration, coordination, and management within a significant group of people.

LR-ISG-2011-05 states that any enhancements to the existing programmatic activities for the ongoing review of operating experience that are necessary for license renewal should be put in place no later than the date the renewed operating licenses are issued. The applicant described several enhancements; however, it plans to implement them after issuance of the renewed licenses. Therefore, the staff could not determine whether operating experience related to aging management and age-related degradation will be considered in the period between issuance of the renewed licenses and implementation of the enhancements. The staff identified this issue as OI 3.0.5-1.

The applicant responded to OI 3.0.5-1 by letter dated September 12, 2012. The applicant stated that, in the period between issuance of the renewed licenses and implementation of the enhancements, it will consider operating experience related to aging management and age-related degradation in accordance with its existing processes. The applicant also stated that, if the enhancements are not implemented by the time the renewed licenses are issued, it will review all LR-ISG documents issued before implementation of the enhancements and the first revision of the GALL Report issued after implementation of the enhancements to identify significant guidance changes driven by industry operating experience that should be incorporated into the aging management activities.

The staff reviewed the applicant's response to OI 3.0.5-1 and determined that, as proposed, it would allow a 2-year period after license renewal before operating experience related to aging is considered in maintaining the AMPs. As such, this consideration of operating experience will begin at a later date rather than immediately upon receipt of the renewed operating licenses. The staff determined that the response does not provide reasonable assurance that the applicant will consider relevant plant-specific and industry operating experience and incorporate it into the aging management activities on an ongoing basis. Therefore, by letter dated October 10, 2012, the staff issued RAI B.1.4-4 requesting the applicant to clearly address how plant-specific and industry operating experience will be considered on an ongoing basis before full implementation of the Operating Experience program enhancements.

The applicant responded to RAI B.1.4-4 by letter dated October 12, 2012. The response removes the applicant's compensatory plan to review LR-ISG documents and GALL Report revision as an alternative to implementing the enhancements before issuance of the renewed licenses. Instead, the response states that all of the previously described enhancements to the

Operating Experience program will be implemented no later than the date when the renewed operating licenses are issued and the associated activities will be conducted on an ongoing basis throughout the terms of the renewed licenses. The staff reviewed this response and finds it acceptable because the implementation date for the enhancements is consistent with the guidance in LR-ISG-2011-05. The applicant's implementation of these enhancements, in conjunction with its existing operating experience review activities, will ensure that age-related degradation and aging management is appropriately addressed in the ongoing processing of plant-specific and industry operating experience. The staff's concern described in RAI B.1.4-4 is resolved and OI 3.0.5-1 is closed.

Based on its review of the application and the applicant's responses to RAIs B.1.4-1, B.1.4-2, and B.1.4-4, the staff determined that the applicant's programmatic activities for the ongoing review of operating experience are acceptable for (a) the systematic review of plant-specific and industry operating experience to ensure that the license renewal AMPs are and will continue to be effective in managing the aging effects for which they are credited, and (b) for the enhancement to or development of new AMPs when it is determined through the evaluation of operating experience that the effects of aging may not be adequately managed.

3.0.5.3 UFSAR Supplement

The staff reviewed the USAR supplement in LRA Appendix A to determine whether the applicant provided an adequate summary description of the programmatic activities for the ongoing review of operating experience. The staff found no such description. By letter dated February 16, 2012, the staff issued RAI A.1-1, requesting that the applicant provide a summary description of these activities for the USAR supplement required by 10 CFR 54.21(d).

The applicant's response to RAI A.1-1, provided by letter dated March 13, 2012, revises the UFSAR supplement to include LRA Section A.1.6, which provides a summary description of the operating experience review activities and identifies enhancements to the existing Operating Experience program. However, this description states that the enhancements will be implemented before the period of extended operation. The staff issued RAI B.1.4-2, by letter dated June 12, 2012, requesting the applicant to provide further clarification regarding implementation of actions associated with the consideration of operating experience for AMPs. By letter dated June 19, 2012, the applicant responded to RAI B.1.4-2 stating that the Operating Experience program enhancements will be implemented within 2 years following receipt of the renewed operating licenses. The applicant also explained its reasoning and justification for this timetable. However, the applicant did not update the UFSAR supplement to reflect that the proposed enhancements will be implemented within 2 years following receipt of the renewed operating licenses. Therefore, by letter dated July 10, 2012, the staff issued RAI B.1.4-3, requesting that the applicant update the UFSAR supplement to be consistent with the response to RAI B.1.4-2. By letter dated July 11, 2012, the applicant revised LRA Section A.1.6, accordingly.

Although the applicant included the enhancement implementation schedule in the revised UFSAR supplement summary description, as discussed in SER Section 3.0.5.2, the staff could not determine whether operating experience related to aging management and age-related degradation will be considered in the period between issuance of the renewed licenses and implementation of the enhancements. The staff identified this issue as OI 3.0.5-1.

In its response to OI 3.0.5-1, the applicant revised the UFSAR supplement to state that, if the

Operating Experience program enhancements are not implemented by the time the renewed licenses are issued, it will review all LR-ISG documents issued before implementation of the enhancements and the first revision of the GALL Report issued after implementation of the enhancements to identify significant guidance changes driven by industry operating experience that should be incorporated into the aging management activities. The staff reviewed this revision to the UFSAR supplement and determined that it would allow a 2-year period after license renewal before operating experience related to aging is considered in maintaining the aging management programs. As such, the staff determined that the proposed UFSAR supplement does not provide reasonable assurance that the applicant will consider relevant plant-specific and industry operating experience and incorporate it into the aging management activities on an ongoing basis. By letter dated October 10, 2012, the staff issued RAI B.1.4-4 requesting that the applicant revise the UFSAR supplement to clearly address how plant-specific and industry operating experience will be considered on an ongoing basis before full implementation of the Operating Experience program enhancements.

In its response to RAI B.1.4-4, the applicant revised UFSAR Section A.1.6 to state that the enhancements will be implemented no later than the date when the renewed operating licenses are issued and conducted on an ongoing basis throughout the terms of the renewed licenses. As discussed in SER 3.0.5.2, the staff finds this implementation schedule acceptable and capturing this schedule in the UFSAR supplement summary description provides assurance that operating experience related to aging management and age-related degradation will be considered on an ongoing basis. Therefore, the staff finds that the UFSAR supplement summary description of the programmatic operating experience review activities is sufficiently comprehensive such that later changes can be controlled by 10 CFR 50.59. The staff's concern described in RAI B.1.4 4 is resolved and OI 3.0.5 1 is closed.

3.0.5.4 Conclusion

Based on the staff's review of the applicant's programmatic activities for the ongoing review of operating experience and the information provided by the applicant in the LRA, in response to RAIs B.1.4-1, B.1.4-2, B.1.4-3, and B.1.4-4, and with consideration of the guidance in LR-ISG-2011-05, the staff concluded that the applicant has demonstrated that operating experience will be reviewed on an ongoing basis from the time of issuance of the renewed licenses and the effects of aging will be adequately managed so that the intended functions 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 USAR supplement for these activities and concludes that it provides an adequate summary description, as required by 10 CFR 54.21(d).

3.1 Aging Management of Reactor Vessel, Internals and Reactor Coolant System

This SER section documents the staff's review of the applicant's AMR results for the reactor vessel, internals, and RCS components and component groups of:

- RCPB
- RPV
- RVI

3.1.1 Summary of Technical Information in the Application

LRA Section 3.1 provides AMR results for the reactor vessel, RVIs, and RCS components and component groups. LRA Table 3.1.1, "Summary of Aging Management Evaluations for the Reactor Vessel, Internals, and Reactor Coolant System," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the reactor vessel, RVIs, and RCS components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.1.2 Staff Evaluation

The staff reviewed LRA Section 3.1 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the reactor vessel, RVIs, and RCS components within the scope of license renewal and subject to an AMR, 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 conducted a review of AMRs to ensure the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA is applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's evaluation are documented in SER Section 3.1.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.1.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.1.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed are appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.1.2.3.

For SSCs that the applicant claimed are not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to verify the applicant's claims.

Table 3.1-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.1 and addressed in the GALL Report.

Table 3.1-1 Staff Evaluation for Reactor Vessel, Reactor Vessel Internals and Reactor Coolant System Components in the SRP-LR

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
High-strength, low-alloy steel top head closure stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-1)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Nickel alloy tubes and sleeves exposed to reactor coolant and secondary feedwater/steam (3.1.1-2)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.1)
Stainless steel or nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-3)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel pressure vessel support skirt and attachment welds (3.1.1-4)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel, stainless steel, or steel (with stainless steel or nickel alloy cladding) steam generator components, pressurizer relief tank components or piping components or bolting (3.1.1-5)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without nickel alloy or stainless steel cladding), or stainless steel; or nickel alloy reactor coolant pressure boundary components: piping, piping components, and piping elements exposed to reactor coolant (3.1.1-6)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (See SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel alloy or stainless steel cladding), or stainless steel; or nickel alloy reactor vessel components: flanges; nozzles; penetrations; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant (3.1.1-7)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)
Steel (with or without nickel alloy or stainless steel cladding), or stainless steel; or nickel alloy steam generator components exposed to reactor coolant (3.1.1-8)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without nickel alloy or stainless steel cladding), stainless steel; nickel alloy RCPB piping; flanges; nozzles & safe ends; pressurizer shell heads & welds; heater sheaths & sleeves; penetrations; thermal sleeves exposed to reactor coolant (3.1.1-9)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.1)
Steel (with or without nickel alloy or stainless steel cladding), stainless steel; nickel alloy reactor vessel flanges; nozzles; penetrations; pressure housings; safe ends; thermal sleeves; vessel shells, heads and welds exposed to reactor coolant (3.1.1-10)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation, and for Class 1 components environmental effects on fatigue are to be addressed (see SRP, Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.1)
Steel or stainless steel pump and valve closure bolting exposed to high temperatures and thermal cycles (3.1.1-11)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA evaluated for the period of extended operation; check ASME Code limits for allowable cycles (less than 7,000 cycles) of thermal stress range (see SRP Section 4.3 "Metal Fatigue," for acceptable methods to comply with 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator components: upper and lower shells, transition cone; new transition cone closure weld exposed to secondary feedwater or steam (3.1.1-12)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry," and, for Westinghouse Model 44 and 51 S/G, if corrosion of the shell is found, additional inspection procedures are developed	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.2(1) and 3.1.2.2.2(2))
Steel (with or without stainless steel cladding) reactor vessel beltline shell, nozzles, and welds exposed to reactor coolant and neutron flux (3.1.1-13)	Loss of fracture toughness caused by neutron irradiation embrittlement	TLAA is to be evaluated in accordance with Appendix G of 10 CFR Part 50 and RG 1.99. The applicant may choose to demonstrate that the materials of the nozzles are not controlling for the TLAA evaluations	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.1.2.2.3(1))
Steel (with or without cladding) reactor vessel beltline shell, nozzles, and welds; safety injection nozzles (3.1.1-14)	Loss of fracture toughness caused by neutron irradiation embrittlement	Chapter XI.M31, "Reactor Vessel Surveillance"	Yes	Reactor Vessel Surveillance	Consistent with the GALL Report (see SER Section 3.1.2.2.3(2))
Stainless steel and nickel alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-15)	Reduction in ductility and fracture toughness caused by neutron irradiation	Ductility - Reduction in Fracture Toughness is a TLAA to be evaluated for the period of extended operation (see SRP, Section 4.7, "Other Plant-Specific TLAAs," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.3(3))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy top head enclosure vessel flange leak detection line (3.1.1-16)	Cracking caused by SCC, intergranular SCC	A plant-specific aging management program is to be evaluated because existing programs may not be capable of mitigating or detecting crack initiation and growth caused by SCC in the vessel flange leak detection line	Yes	Not applicable	Not applicable to LGS (see SER Section 3.1.2.2.4(1))
Stainless steel isolation condenser components exposed to reactor coolant (3.1.1-17)	Cracking caused by SCC, intergranular SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry" for BWR water, and a plant-specific verification program	Yes	Not applicable	Not applicable to LGS (see SER Section 3.1.2.2.4(2))
Reactor vessel shell fabricated of SA508-Cl 2 forgings clad with stainless steel using a high-heat-input welding process exposed to reactor coolant (3.1.1-18)	Crack growth caused by cyclic loading	Growth of intergranular separations is a TLAA evaluated for the period of extended operation The Standard Review Plan, Section 4.7, "Other Plant-Specific Time-Limited Aging Analysis," provides guidance for meeting the requirements of 10 CFR 54.21(c))	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.5)
Stainless steel reactor vessel closure head flange leak-detection line and bottom-mounted instrument guide tubes (external to reactor vessel) (3.1.1-19)	Cracking caused by SCC	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.6(1))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cast austenitic stainless steel Class 1 piping, piping components, and piping elements exposed to reactor coolant (3.1.1-20)	Cracking caused by SCC	Chapter XI.M2, "Water Chemistry" and, for CASS components that do not meet the NUREG-0313 guidelines, a plant-specific aging management program	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.6(2))
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-21)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components. The ISI program is to be augmented by a plant-specific verification program	Yes	Not applicable	Not applicable to LGS (see SER Section 3.1.2.2.7)
Steel steam generator feedwater impingement plate and support exposed to secondary feedwater (3.1.1-22)	Loss of material caused by erosion	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.8)
Stainless steel or nickel alloy PWR reactor vessel internal components (inaccessible locations) exposed to reactor coolant and neutron flux (3.1.1-23)	Cracking caused by SCC and irradiation-assisted SCC	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.9)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel alloy PWR reactor vessel internal components (inaccessible locations) exposed to reactor coolant and neutron flux (3.1.1-24)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.10)
Steel (with nickel alloy cladding) or nickel alloy steam generator primary side components: divider plate and tube-to-tube sheet welds exposed to reactor coolant (3.1.1-25)	Cracking caused by primary water SCC	Chapter XI.M2, "Water Chemistry"	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.11(1) and 3.1.2.2.11(2))
Stainless steel Combustion Engineering core support barrel assembly: lower flange weld exposed to reactor coolant and neutron flux. Upper internals assembly: fuel alignment plate (applicable to plants with core shrouds assembled with full height shroud plates) exposed to reactor coolant and neutron flux. Lower support structure: core support plate (applicable to plants with a core support plate) exposed to reactor coolant and neutron flux (3.1.1-26)	Cracking caused by fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry," if fatigue life cannot be confirmed by TLAA	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.12)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy Westinghouse control rod guide tube assemblies, guide tube support pins exposed to reactor coolant and neutron flux (3.1.1-27)	Cracking caused by SCC and fatigue	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.13)
Nickel alloy Westinghouse control rod guide tube assemblies, guide tube support pins, and Zircaloy-4 Combustion Engineering in-core instrumentation thimble tubes exposed to reactor coolant and neutron flux (3.1.1-28)	Loss of material caused by wear	A plant-specific aging management program is to be evaluated	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.2.14)
Nickel alloy core shroud and core plate access hole cover (welded covers) exposed to reactor coolant (3.1.1-29)	Cracking caused by SCC, intergranular SCC, irradiation-assisted SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry," and for BWRs with a crevice in the access hole covers, augmented inspection using UT or other acceptable techniques	No	BWR Vessel Internals and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.2)
Stainless steel or nickel alloy penetration: drain line exposed to reactor coolant (3.1.1-30)	Cracking caused by SCC, intergranular SCC, cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry"	No	ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Water Chemistry	Consistent with the GALL Report
Steel and stainless steel isolation condenser components exposed to reactor coolant (3.1.1-31)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and Chapter XI.M2, "Water Chemistry"	No	One-Time Inspection and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, nickel alloy, or CASS reactor vessel internals, core support structure, exposed to reactor coolant and neutron flux (3.1.1-32)	Cracking, or loss of material caused by wear	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	Yes	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel, steel with stainless steel cladding Class 1 reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-33)	Cracking caused by SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for ASME components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel, steel with stainless steel cladding pressurizer relief tank (tank shell and heads, flanges, nozzles) exposed to treated borated water >60 °C (>140 °F) (3.1.1-34)	Cracking caused by SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for ASME components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel, steel with stainless steel cladding reactor coolant system cold leg, hot leg, surge line, and spray line piping and fittings exposed to reactor coolant (3.1.1-35)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No,	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel, stainless steel pressurizer integral support exposed to air with metal temperature up to 288 °C (550 °F) (3.1.1-36)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel reactor vessel flange (3.1.1-37)	Loss of material caused by wear	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Cast austenitic stainless steel Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant >250 °C (>482 °F) (3.1.1-38)	Loss of fracture toughness caused by thermal aging embrittlement	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components. For pump casings and valve bodies, screening for susceptibility to thermal aging is not necessary.	No	ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.1.2.1.4)
Steel, stainless steel, or steel with stainless steel cladding Class 1 piping, fittings and branch connections < NPS 4 exposed to reactor coolant (3.1.1-39)	Cracking caused by SCC, intergranular SCC (for stainless steel only), and thermal, mechanical, and vibratory loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, Chapter XI.M2, "Water Chemistry," and XI.M35, "One-Time Inspection of ASME Code Class 1 Small-bore Piping"	No	ASME Code Section XI Inservice Inspections, Subsections IWB, IWC, and IWD, Water Chemistry, and One-Time Inspection of ASME Code Class 1 Small-bore Piping	Consistent with the GALL Report
Steel with stainless steel or nickel alloy cladding; or stainless steel pressurizer components exposed to reactor coolant (3.1.1-40)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Nickel alloy core support pads; core guide lugs exposed to reactor coolant (3.1.1-40x)	Cracking caused by primary water SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy core shroud and core plate access hole cover (mechanical covers) exposed to reactor coolant (3.1.1-41)	Cracking caused by SCC, intergranular SCC, irradiation-assisted SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to LGS (see SER Section 3.1.2.1.1)
Steel with stainless steel or nickel alloy cladding or stainless steel primary side components; steam generator upper and lower heads, and tube sheet weld; or pressurizer components exposed to reactor coolant (3.1.1-42)	Cracking caused by SCC, primary water SCC	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy reactor vessel internals exposed to reactor coolant (3.1.1-43)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 1 components, and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel Internals and Water Chemistry	Consistent with the GALL Report (see SER Section 3.1.2.1.5)
Steel steam generator secondary manways and handholds (cover only) exposed to air with leaking secondary-side water and/or steam (3.1.1-44)	Loss of material caused by erosion	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" for Class 2 components	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy and steel with nickel alloy cladding reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-45)	Cracking caused by primary water SCC	Chapter XI.M1, "ASME Code Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry," and, for nickel alloy, Chapter XI.M11B, "Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid-induced Corrosion in RCPB Components (PWRs Only)"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel, nickel alloy, nickel alloy welds and/or buttering CRD head penetration pressure housing or nozzles safe ends and welds (inlet, outlet, safety injection) exposed to reactor coolant (3.1.1-46)	Cracking caused by SCC, primary water SCC	Chapter XI.M1, "ASME Code Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry," and, for nickel alloy, Chapter XI.M11B, "Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid-induced corrosion in RCPB Components (PWRs Only)"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel, nickel alloy CRD head penetration pressure housing exposed to reactor coolant (3.1.1-47)	Cracking caused by SCC, primary water SCC	Chapter XI.M1, "ASME Code Section XI ISI, IWB, IWC & IWD," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel external surfaces: reactor vessel top head, reactor vessel bottom head, reactor coolant pressure boundary piping or components adjacent to dissimilar metal (Alloy 82/182) welds exposed to air with borated water leakage (3.1.1-48)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion," and Chapter XI.M11B, "Cracking of Nickel Alloy Components and Loss of Material Due to Boric Acid-Induced Corrosion in RCPB Components (PWRs Only)"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel reactor coolant pressure boundary external surfaces or closure bolting exposed to air with borated water leakage (3.1.1-49)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
CASS Class 1 piping, piping component, and piping elements and CRD pressure housings exposed to reactor coolant >250 °C (>482 °F) (3.1.1-50)	Loss of fracture toughness caused by thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	Not applicable	Not applicable to LGS (See SER Section 3.1.2.1.1)
Stainless steel or nickel alloy Babcock & Wilcox reactor internal components exposed to reactor coolant and neutron flux (3.1.1-51)	Cracking caused by SCC, irradiation-assisted SCC, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy Combustion Engineering reactor internal components exposed to reactor coolant and neutron flux (3.1.1-52)	Cracking caused by SCC, irradiation-assisted SCC, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-53)	Cracking caused by SCC, irradiation-assisted SCC, or fatigue	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel bottom mounted instrument system flux thimble tubes (with or without chrome plating) exposed to reactor coolant and neutron flux (3.1.1-54)	Loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals," and Chapter XI.M37, "Flux Thimble Tube Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel thermal shield assembly, thermal shield flexures exposed to reactor coolant and neutron flux (3.1.1-55)	Cracking caused by fatigue; Loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy Combustion Engineering reactor internal components exposed to reactor coolant and neutron flux (3.1.1-56)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy Babcock & Wilcox reactor internal components exposed to reactor coolant and neutron flux (3.1.1-58)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension caused by void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material because of wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel or nickel alloy Westinghouse reactor internal components exposed to reactor coolant and neutron flux (3.1.1-59)	Loss of fracture toughness caused by neutron irradiation embrittlement; or changes in dimension because of void swelling; or loss of preload caused by thermal and irradiation enhanced stress relaxation; or loss of material caused by wear	Chapter XI.M16A, "PWR Vessel Internals"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel piping, piping components, and piping elements exposed to reactor coolant (3.1.1-60)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Flow-Accelerated Corrosion	Consistent with the GALL Report (see SER Section 3.1.2.1)
Steel steam generator steam nozzle and safe end, feedwater nozzle and safe end, AFW nozzles and safe ends exposed to secondary feedwater/steam (3.1.1-61)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
High-strength, low-alloy steel, or stainless steel closure bolting; stainless steel CRD head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-62)	Cracking caused by SCC	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel or stainless steel closure bolting exposed to air with reactor coolant leakage (3.1.1-63)	Loss of material caused by general (steel only), pitting, and crevice corrosion or wear	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel closure bolting exposed to air-indoor, uncontrolled (3.1.1-64)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel CRD head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-65)	Loss of material caused by wear	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
High-strength, low-alloy steel, or stainless steel closure bolting; stainless steel CRD head penetration flange bolting exposed to air with reactor coolant leakage (3.1.1-66)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel or stainless steel closure bolting exposed to air-indoor with potential for reactor coolant leakage (3.1.1-67)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Nickel alloy steam generator tubes exposed to secondary feedwater or steam (3.1.1-68)	Changes in dimension ("denting") caused by corrosion of carbon steel tube support plate	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam (3.1.1-69)	Cracking caused by outer diameter SCC and intergranular attack	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Nickel alloy steam generator tubes, repair sleeves, and tube plugs exposed to reactor coolant (3.1.1-70)	Cracking caused by primary water SCC	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam (3.1.1-71)	Cracking caused by SCC or other mechanism(s); loss of material due general (steel only), pitting, and crevice corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel steam generator tube support plate, tube bundle wrapper, supports, and mounting hardware exposed to secondary feedwater or steam (3.1.1-72)	Loss of material caused by erosion, general, pitting, and crevice corrosion, ligament cracking caused by corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Nickel alloy steam generator tubes and sleeves exposed to phosphate chemistry in secondary feedwater or steam (3.1.1-73)	Loss of material caused by wastage and pitting corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel steam generator upper assembly and separators including feedwater inlet ring and support exposed to secondary feedwater or steam (3.1.1-74)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel steam generator tube support lattice bars exposed to secondary feedwater or steam (3.1.1-75)	Wall thinning caused by flow-accelerated corrosion and general corrosion	Chapter XI.M19, "Steam Generators," and Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel, chrome plated steel, stainless steel, nickel alloy steam generator U-bend supports including anti-vibration bars exposed to secondary feedwater or steam (3.1.1-76)	Loss of material caused by fretting	Chapter XI.M19, "Steam Generators"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy steam generator tubes and sleeves exposed to secondary feedwater or steam (3.1.1-77)	Loss of material caused by wear and fretting	Chapter XI.M19, "Steam Generators"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Nickel alloy steam generator components such as secondary side nozzles (vent, drain, and instrumentation) exposed to secondary feedwater or steam (3.1.1-78)	Cracking caused by SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection," or Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD."	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-79)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel or steel with stainless steel cladding pressurizer relief tank: tank shell and heads, flanges, nozzles (none-ASME Code Section XI components) exposed to treated borated water >60°C (>140°F) (3.1.1-80)	Cracking caused by SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel pressurizer spray head exposed to reactor coolant (3.1.1-81)	Cracking caused by SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Nickel alloy pressurizer spray head exposed to reactor coolant (3.1.1-82)	Cracking caused by SCC, primary water SCC	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel steam generator shell assembly exposed to secondary feedwater or steam (3.1.1-83)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Steel top head enclosure (without cladding) top head nozzles (vent, top head spray or RCIC, and spare) exposed to reactor coolant (3.1.1-84)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel, nickel alloy, and steel with nickel alloy or stainless steel cladding reactor vessel flanges, nozzles, penetrations, safe ends, vessel shells, heads and welds exposed to reactor coolant (3.1.1-85)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel steam generator primary side divider plate exposed to reactor coolant (3.1.1-86)	Cracking caused by SCC	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel or nickel alloy PWR reactor internal components exposed to reactor coolant and neutron flux (3.1.1-87)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel; steel with nickel alloy or stainless steel cladding; and nickel alloy reactor coolant pressure boundary components exposed to reactor coolant (3.1.1-88)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-89)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-90)	Loss of material caused by pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
High-strength low-alloy steel closure head stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-91)	Cracking caused by SCC; loss of material caused by general, pitting, and crevice corrosion, or wear (BWR)	Chapter XI.M3, "Reactor Head Closure Stud Bolting"	No	Reactor Head Closure Stud Bolting	Consistent with the GALL Report
High-strength low-alloy steel closure head stud assembly exposed to air with potential for reactor coolant leakage (3.1.1-92)	Cracking caused by SCC; loss of material caused by general, pitting, and crevice corrosion, or wear (PWR)	Chapter XI.M3, "Reactor Head Closure Stud Bolting"	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Copper-alloy >15% Zn or > 8% Al piping, piping components, and piping elements exposed to closed cycle cooling water (3.1.1-93)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching "	No	Not applicable	Not applicable to BWRs (see SER Section 3.1.2.1.1)
Stainless steel and nickel alloy vessel shell attachment welds exposed to reactor coolant (3.1.1-94)	Cracking caused by SCC, intergranular SCC	Chapter XI.M4, "BWR Vessel ID Attachment Welds," and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel ID Attachment Welds and Water Chemistry	Consistent with the GALL Report
Steel (with or without stainless steel cladding) feedwater nozzles exposed to reactor coolant (3.1.1-95)	Cracking caused by cyclic loading	Chapter XI.M5, "BWR Feedwater Nozzle"	No	BWR Feedwater Nozzle	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with or without stainless steel cladding) CRD return line nozzles exposed to reactor coolant (3.1.1-96)	Cracking caused by cyclic loading	Chapter XI.M6, "BWR Control Rod Drive Return Line Nozzle"	No	BWR CRD Return Line Nozzle	Consistent with the GALL Report
Stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS; nozzle safe ends and associated welds (3.1.1-97)	Cracking caused by SCC, intergranular SCC	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	BWR Stress Corrosion Cracking, Water Chemistry, One-Time Inspection, and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWB	Consistent with the GALL Report (see SER Section 3.1.2.1.6)
Stainless steel or nickel alloy penetrations: instrumentation and SLC exposed to reactor coolant (3.1.1-98)	Cracking caused by SCC, intergranular SCC, cyclic loading	Chapter XI.M8, "BWR Penetrations," and Chapter XI.M2, "Water Chemistry"	No	BWR Penetrations and Water Chemistry	Consistent with the GALL Report
CASS; PH martensitic stainless steel; martensitic stainless steel; X-750 alloy reactor internal components exposed to reactor coolant and neutron flux (3.1.1-99)	Loss of fracture toughness caused by thermal aging and neutron irradiation embrittlement	Chapter XI.M9, "BWR Vessel Internals"	No	BWR Vessel Internals	Consistent with the GALL Report
Stainless steel reactor vessel internals components (jet pump wedge surface) exposed to reactor coolant (3.1.1-100)	Loss of material caused by wear	Chapter XI.M9, "BWR Vessel Internals"	No	BWR Vessel Internals	Consistent with the GALL Report
Stainless steel steam dryers exposed to reactor coolant (3.1.1-101)	Cracking caused by flow-induced vibration	Chapter XI.M9, "BWR Vessel Internals" for steam dryer	No	BWR Vessel Internals	Consistent with the GALL Report
Stainless steel fuel supports and CRD assemblies CRD housing exposed to reactor coolant (3.1.1-102)	Cracking caused by SCC, intergranular SCC	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel Internals and Water Chemistry	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	Recommended AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel and nickel alloy reactor internal components exposed to reactor coolant and neutron flux (3.1.1-103)	Cracking caused by SCC, intergranular SCC, irradiation-assisted SCC	Chapter XI.M9, "BWR Vessel Internals," and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel Internals and Water Chemistry	Consistent with the GALL Report
X-750 alloy reactor vessel internal components exposed to reactor coolant and neutron flux (3.1.1-104)	Cracking caused by intergranular SCC	Chapter XI.M9, "BWR Vessel Internals" for core plate, and Chapter XI.M2, "Water Chemistry"	No	BWR Vessel Internals and Water Chemistry	Consistent with the GALL Report
Steel piping, piping components, and piping element exposed to concrete (3.1.1-105)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557, and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	Not applicable	Not applicable to LGS (see SER Section 3.1.2.1.1)
Nickel alloy piping, piping components, and piping element exposed to air-indoor, uncontrolled, or air with borated water leakage (3.1.1-106)	None	None	NA	None	Consistent with the GALL Report
Stainless steel piping, piping components, and piping element exposed to gas, concrete, air with borated water leakage, air-indoor, uncontrolled (3.1.1-107)	None	None	NA	None	Consistent with the GALL Report

The staff's review of the reactor vessel, RVIs, and RCS component groups followed any one of several approaches. One approach, documented in SER Section 3.1.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.1.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.1.2.3, reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the reactor vessel, RVIs, and RCS components is documented in SER Section 3.0.3.

3.1.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.1.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the reactor vessel, RVIs, and RCS components:

- ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD
- BWR CRD Return Line Nozzle
- BWR Feedwater Nozzle
- BWR Penetrations
- BWR Stress Corrosion Cracking
- BWR Vessel ID Attachment Welds
- BWR Vessel Internals
- Bolting Integrity
- Flow-Accelerated Corrosion
- Inspection of internal Surfaces in Miscellaneous Piping and Ducting Components
- One-Time Inspection
- One-Time Inspection of ASME Code Class 1 Small-Bore Piping
- Reactor Head Closure Stud Bolting
- Reactor Vessel Surveillance
- TLAA
- Water Chemistry

LRA Tables 3.1.2-1 through 3.1.2-3 summarize AMRs for the RCPB, RPV, and RVIs components and indicate AMRs claimed to be consistent with the GALL Report.

The staff reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

LRA Table 3.1.1, item 3.1.1-60, addresses steel piping components exposed to reactor coolant that are being managed for wall thinning caused by flow-accelerated corrosion. The GALL Report recommends GALL Report AMP XI.M17, "Flow-Accelerated Corrosion," to manage wall thinning for this component group. The applicant stated that this item is not applicable because there are no steel piping, piping components, or piping elements exposed to reactor coolant that are susceptible to wall thinning caused by flow-accelerated corrosion in the reactor vessel, internals and reactor coolant system. The staff evaluated the applicant's claim and reviewed the information provided in EPRI 1013013, "An Evaluation of Flow-Accelerated Corrosion in the Bottom Head Drain Lines of Boiling Water Reactors," which concluded that both Limerick Generating Station (LGS) units were viewed as having very limited susceptibility to damage from this concern caused by the high level of oxidant present. However, a more recent EPRI document, 1016949, "Flow-Accelerated Corrosion in Boiling Water Reactor Bottom Head Drain Lines – 2008 Update," concludes that some degree of inspection of the drain lines should be performed. It was not clear to the staff how the applicant's claim that no components exposed to reactor coolant are susceptible to wall thinning in the RCS was valid. By letter dated February 14, 2012, the staff issued RAI 3.1.1.60-1 requesting the applicant to provide its bases for its claim that there are no steel piping components exposed to reactor coolant that are susceptible to flow-accelerated corrosion in the RCS.

In its response dated March 13, 2012, the applicant stated that the bottom head drain line includes approximately a 7-foot-long section of 2-inch-diameter carbon steel piping, and although it is excluded from inspection requirements, it is considered susceptible to flow-accelerated corrosion. The response also stated that an extent of condition review identified additional RCS components within the feedwater system that are being managed by the Flow-Accelerated Corrosion program, but were not included in LRA Table 3.1.2-1. The response also revised LRA Table 3.1.2-1, to include item 3.1.1-60 under "Class 1 Piping and Fittings and Branch Connections less than NPS 4," and "Piping, piping components, and piping elements." The applicant's response is acceptable because the carbon steel components susceptible to flow-accelerated corrosion addressed in item 3.1.1-60 are now included in the revised LRA Table 3.1.2-1. The staff's concern described in RAI 3.1.1-60 is resolved.

LRA Table 3.1.1, item 3.1.1-99 addresses CASS, precipitation hardened stainless steel, martensitic stainless steel and X-750 alloy reactor internal components exposed to reactor coolant and neutron flux. For the AMR item that cites generic note C, the LRA credits BWR Vessel Internals program to manage loss of fracture toughness caused by thermal aging embrittlement and neutron irradiation embrittlement of the CASS RVI components. The GALL Report recommends GALL Report AMP XI.M9, "BWR Vessel Internals" to ensure that this aging effect is adequately managed.

GALL Report AMP XI.M9 states that it does not directly monitor for loss of fracture toughness that is induced by thermal aging or neutron irradiation embrittlement. The GALL Report also states that the impact of loss of fracture toughness on component integrity is indirectly managed by using visual or volumetric examination techniques to monitor for cracking in the components. The GALL Report also states that loss of fracture toughness caused by neutron embrittlement in CASS materials can occur with a neutron fluence greater than 1.0E+17 n/cm^2 (E > 1 MeV) and loss fracture toughness of CASS material caused by thermal embrittlement is dependent on the material's casting method, molybdenum content, and ferrite content.

In its review, the staff noted that the BWR Vessel Internal program includes periodic visual inspections based on material susceptibility evaluation. However, LRA Section B.2.1.9 for the BWR Vessel Internals program does not address the screening criteria for the susceptibility of CASS components to loss of fracture toughness. Therefore, the staff needed to clarify whether the applicant's screening criteria for material susceptibility are consistent with the GALL Report.

By letter dated January 18, 2012, the staff issued RAI 3.1.1.99-1, requesting that the applicant describe the screening criteria for the susceptibility of CASS RVI components to loss of fracture toughness caused by thermal aging and neutron irradiation embrittlement. The staff also requested that if the screening criteria are not consistent with the GALL Report, the applicant justify why the applicant's screening criteria are adequate to manage the aging effect.

In its response dated February 16, 2012, the applicant stated that the screening criteria used to determine the susceptibility of CASS RVI components to loss of fracture toughness are consistent with GALL Report AMP XI.M9. The applicant also confirmed that the screening criteria to determine the susceptibility of CASS components to thermal aging are based on the casting method, molybdenum content, and percent ferrite, consistent with criteria set forth in the NRC letter, dated May 19, 2000, which is referenced in the GALL Report. The applicant further indicated that if casting method, ferrite or molybdenum content cannot be determined for any CASS components, they will be assumed to be susceptible to thermal aging for the purposes of determining program examination requirements. In addition, the applicant stated that CASS components that are exposed to neutron fluence in excess of 1.0E+17 n/cm^2 (E > 1 MeV) are susceptible to neutron irradiation embrittlement. In its review, the staff finds the applicant's response acceptable because the applicant's screening criteria used to determine the susceptibility of CASS RVI components to loss of fracture toughness are consistent with the GALL Report.

The staff's evaluation of the BWR Vessel Internals program is documented in SER Section 3.0.3.2.2. In its review of the components associated with items 3.1.1-99, the staff finds the applicant's proposal to manage loss of fracture toughness for these components acceptable because the BWR Vessel Internals program includes periodic visual inspections based on the adequate screening criteria to determine the material susceptibility to loss of fracture toughness, consistent with the GALL Report.

LRA Table 3.1.2-3 contains an AMR result for stainless steel (part of jet pump assembly) components in a reactor coolant and neutron flux environment with an aging effect of loss of preload being managed by the BWR Vessels Internals program. The staff noted that loss of preload is usually associated with bolts and in the reactor coolant and neutron flux environment is addressed as a TLAA. Therefore, by letter dated January 17, 2012, the staff issued RAI 3.1.2.3-1 requesting the applicant to clarify what component is referenced in the AMR item, and what specific features or activities of the BWR Vessel Internals program will manage the aging effect of loss of preload. By letter dated February 15, 2012 the applicant responded to RAI 3.1.2.3-1 and stated that the component referenced in the AMR is the jet pump slip joint repair clamps and that the AMR referenced in the staff's RAI was deleted in response to RAI 4.6.9-1 because the TLAA analysis provided in LRA Section 4.6.9 was revised to document that the fluence value used to determine loss of preload in the design analysis will not be exceeded during the period of extended operation. The staff finds this response acceptable because the applicant clarified that the aging effect of loss of preload will not be managed by the BWR Vessel Internals program. The staff's evaluation of the associated TLAA is documented in SER Section 4.6.9.2. As such, the staff's concern described in RAI 3.1.2.3-1 is resolved.

The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.1.1 items 3.1.1-41, and 3.1.1.105, the applicant claimed that they were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.1.1 items 3.1.1-32 through 3.1.1-37, 3.1.1-40, 3.1.1-40x, 3.1.1-42, 3.1.1-44, through 3.1.1-49, 3.1.1-51 through 3.1.1-59, 3.1.1-61, 3.1.1-64, 3.1.1-65, 3.1.1-66, 3.1.1-68 through 3.1.1-78, 3.1.1-80, through 3.1.1-83, 3.1.1-86 through 3.1.1-90, 3.1.1-92, and 3.1.1.93

the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to PWRs. The staff reviewed the SRP-LR, confirmed these items only apply to PWRs, and finds these items are not applicable to LGS.

For LRA Table 3.1.1, item 3.1.1-50, the applicant claimed it was not applicable. The staff reviewed the LRA and confirmed that the applicant's LRA does not have any AMR results that are applicable for this item. As addressed in GALL Report AMP XI.M12, pump casings and valve bodies do not require material screening for susceptibility to thermal aging embrittlement and the existing ASME Code Section XI inspection requirements are adequate to manage loss of fracture toughness caused by thermal aging embrittlement. In addition, LRA Table 3.1.1, item 3.1.1-38 addresses the applicant's aging management for loss of fracture toughness of the Class 1 CASS pump casings and valve bodies.

LRA Table 3.1.1, item 3.1.1-62, addresses high-strength, low-alloy steel, or stainless steel closure bolting and stainless steel CRD head penetration flange bolting exposed to air with reactor coolant leakage. The GALL Report recommends GALL Report AMP XI.M18 "Bolting Integrity" to manage cracking caused by SCC for this component group. The applicant stated that this item is not applicable because it is only applicable to PWR plants. The staff lacks sufficient information to evaluate the applicant's claim because although the SRP-LR states that item 3.1.1-62 is applicable to PWRs, the applicant has carbon and low-alloy steel bolting exposed to air with reactor coolant leakage within the scope of license renewal. The staff noted that the applicant is managing these items for loss of material and loss of preload, but not cracking caused by SCC. By letter dated January 18, 2012, the staff issued RAI 3.1.2.1.1-1 requesting the applicant to state the basis for why cracking caused by SCC is not applicable to carbon and low-alloy steel closure bolting within the scope of license renewal and exposed externally to air with reactor coolant leakage in the RCS.

In its response dated February 16, 2012, the applicant stated that with the exception of the reactor head closure bolting, which is managed by the Reactor Head Closure Stud Bolting program, there are no stainless steel or high-strength carbon or low-alloy steel bolts within the scope of license renewal that are exposed to air with reactor coolant leakage in the RCS; therefore, no bolting other than the reactor head closure studs is susceptible to SCC.

The staff finds the applicant's response acceptable because there are no stainless steel or high-strength carbon or low-alloy steel bolts within the scope of license renewal that are exposed to air with reactor coolant leakage in the RCS that would be managed by the Bolting Integrity program. The staff's concern described in RAI 3.1.2.1.1-1 is resolved.

3.1.2.1.2 Cracking Caused by SCC, Intergranular SCC, and Irradiation-Assisted SCC

LRA Table 3.1.1, item 3.1.1-29 addresses nickel alloy core shroud and core plate access hole cover (welded) components exposed to reactor coolant, which are being managed for cracking caused by SCC, IGSCC, and irradiation-assisted SCC. The LRA credits the BWR Vessel Internals program and the Water Chemistry program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL Report AMP XI.M2, "Water Chemistry," along with augmented inspections for crevice condition for the access hole cover to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those items associated with generic note E, GALL Report AMP XI.M1 recommends using periodic visual, surface, or volumetric examination and leakage testing along with GALL Report AMP XI.M2, which recommends monitoring and controlling known detrimental contaminants in accordance with the recommendations of BWRVIP-190 to manage the aging of this item. In addition, the GALL Report recommends augmented inspection for the welded core plate access hole cover where crevice conditions exist. In its review of components associated with item 3.1.1-29 for which the applicant cited generic note E, the staff noted that the BWR Vessel Internals program is substituted for the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program because it proposes to manage the aging of nickel-alloy and stainless steel RVI components through ISIs in accordance with component-specific BWRVIP documents that include industry-approved inspection procedures and flaw evaluations. The staff noted that the BWRVIP recommended inspections are often more stringent than those inspections specified by ASME Code, Section XI, such as the BWRVIP use of EVT-1 or UT, in place of VT-1 or VT-3 from ISI for select components and locations. The staff noted that the applicant's use of its Water Chemistry program is consistent with the recommendations of the GALL Report.

The staff's evaluation of the BWR Vessel Internals and Water Chemistry programs are documented in SER Sections 3.0.3.2.2 and 3.0.3.1.2, respectively. The staff noted that the Water Chemistry program includes controls of chemistry parameters that create an environment that is not conducive for any form of SCC to occur.

In its review of components associated with item 3.1.1-29, the staff finds the applicant's proposal to manage aging using the BWR Vessel Internals program and Water Chemistry program acceptable because the BWR Vessel Internals program follows the guidelines recommended by the BWRVIP and includes specific flaw evaluation and repair recommendations to facilitate post-inspection review; and the applicant's use of the Water Chemistry program creates an environment that is not conducive for loss of material to occur, and is consistent with the recommendations of the GALL Report.

The staff concludes that 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.3 Loss of Material Caused by General, Pitting, and Crevice Corrosion

LRA Table 3.1.2-1 items associated with LRA Table 3.1.1, item 3.1.1-31, address stainless steel and carbon steel RPV flange leak detection line and carbon steel ASME Code, Class 1, piping and branch connections less then NPS 4 exposed to reactor coolant, which will be managed for loss of material caused by general, pitting, and crevice corrosion. For these AMR items that cite note E with plant-specific note 2, the LRA credits the Water Chemistry program and the One-Time Inspection program to manage the aging effects for steel and stainless steel RPV flange leak detection line and carbon steel ASME Code, Class 1, piping and branch connections less than NPS 4.

The staff noted that LRA Table 3.1.2-1 relates these AMR items with the GALL Report item IV.C1.RP-39, which manages the aging effects of steel and stainless steel isolation condenser components exposed to reactor coolant. The staff also noted that the applicant does not have isolation condenser components in its design; however, the material, environment, and aging effect combination of the GALL Report item IV.C1.RP-39 is applicable to the applicant's components cited in LRA Table 3.1.2-1 (i.e., RPV flange leak detection line and small-bore ASME Code, Class 1, piping and branch connections). Therefore, the staff finds the applicant's AMR result that identifies these components under the GALL Report item IV.C1.RP-39, appropriate. The GALL Report recommends GALL Report AMPs XI.M1, "ASME Code Section XI Inservice Inspection IWB, IWC, and IWD," and XI.M2, "Water Chemistry" to ensure that loss of material caused by general, pitting, and crevice corrosion are adequately managed for steel and stainless steel isolation condenser components exposed to reactor coolant. GALL Report AMP XI.M1 includes VT-2 examination of pressure-retaining components during system leakage testing, which confirms that the component integrity is not affected by loss of material caused by corrosion. In addition, GALL Report AMP XI.M2 includes the specified limits for corrosive substances (such as chlorides, sulfates, and dissolved oxygen), sampling and analysis frequencies for water chemistry parameters, and control of reactor water chemistry to mitigate the environmental effects on loss of material caused by corrosion.

The staff noted that the applicant's carbon steel RPV flange leak detection line is not normally exposed to reactor coolant during normal operation. The staff also noted that the applicant's carbon steel ASME Code, Class 1, piping and branch connections less then NPS 4, are being managed for cracking caused by SCC by the applicant's existing ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, One-Time Inspection of ASME Code Class 1 Small-bore Piping, and Water Chemistry programs, consistent with the GALL Report. The staff's evaluations of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD, One-Time Inspection of ASME Code Class 1 Small-bore Piping, and the Water Chemistry programs are documented in SER Sections 3.0.3.1.1, 3.0.3.1.14, and 3.0.3.1.2, respectively.

In its review of the components associated with LRA item 3.1.1-31, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the One-Time Inspection program and the Water Chemistry program acceptable because the Water Chemistry program includes periodic monitoring of water chemistry conditions, and control of known detrimental contaminants below the specified levels, such that loss of material is mitigated or prevented. In addition, the One-Time Inspection program will confirm the effectiveness of the Water Chemistry program before the period of extended operation.

The staff concludes that for the components associated with LRA item 3.1.1-31, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.4 Loss of Fracture Toughness Due to Thermal Aging Embrittlement

LRA Table 3.1.1, item 3.1.1-38 addresses CASS Class 1 pump casings, and valve bodies and bonnets exposed to reactor coolant greater than 250° C (482 °F). For the AMR item that cites generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of fracture toughness caused by thermal aging embrittlement of the CASS pump casing in the reactor water cleanup (RWCU) system. The GALL Report recommends GALL Report AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD" to ensure that this aging effect is adequately managed for Class 1 components. GALL Report AMP XI.M1 also recommends using visual inspections to manage aging. The LRA does not provide sufficient information on how the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will manage this aging effect for the pump casing as further evaluated below.

In its review, the staff noted that LRA item 3.1.1-38 is associated with SRP-LR Table 3.1-1, ID 38, which addresses aging management for Class 1 RCPB components. Therefore, the staff needed to clarify whether the pump casing in the RWCU system is an ASME Code Class 1 component, for which the GALL Report recommends the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program to manage the aging effect. The staff also needed to clarify whether the operating temperature of the pump casing confirms that loss of fracture toughness caused by thermal aging embrittlement is applicable to this component. The staff further noted that LRA Section B.2.1.26, which describes the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, does not provide specific information about how this program will manage loss of fracture toughness of the pump casing.

By letter dated January 18, 2012, the staff issued RAI 3.1.1.38-1 requesting the applicant to provide additional information to clarify the following items: (1) ASME Code Class of the pump casing in the RWCU system and examination categories and methods for the pump casing, 2) operating temperature of the pump casing to confirm whether loss of fracture toughness caused by thermal aging embrittlement is applicable to this component (i.e., T > 482 °F), (3) operating experience of this component in terms of occurrence of cracking and leakage, and (4) how the applicant's program will manage loss of fracture toughness of the pump casing.

In its response dated February 16, 2012, the applicant stated that the RWCU pump casings are ASME Code Class 3 components. The applicant also indicated that ASME Code Section XI, Subsection IWD, Table IWD-2500-1 provides the examination requirements for ASME Code Class 3 components and ASME Code Table IWD-2500-1 does not include any examination requirements for pump casings. The applicant further confirmed that that the pump casings (RWCU B and C pump casings) on both units are made from CASS material and the operating temperature of the pumps in the RWCU system is nominally 545 °F such that loss of fracture toughness caused by thermal aging embrittlement is applicable to the pump casings. The applicant further confirmed that that the pump casings (RWCU B and C pump casings) on both LGS Units 1 and 2 have not had any indication of flaws, cracking or leakage from the pump casings. In its response, the applicant indicated that consistent with the "detection of aging effects" program element of GALL Report AMP XI.M38, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, will manage loss of fracture toughness for the pump casings by implementing visual inspections for evidence of cracking whenever the pumps are disassembled for maintenance. The applicant further stated that any evidence of cracking identified during visual inspection will be evaluated for potential loss of intended function under the CAP.

In its review, the staff noted that the basis for using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of fracture toughness of the RWCU CASS pump casings has not been identified as an enhancement to the "scope of program" element. The basis also does not establish exactly which type of visual inspections and inspection frequency will be used to detect crack indications as an indirect measure for determining whether loss of fracture toughness is occurring in the RWCU pump casings. In addition, the program does not address how the visual inspection method and frequency will be capable of detecting and resolving flaw sizes that are less than the limiting lower bound critical flaw size for the RWCU pump casings, as assessed for limiting thermal aging embrittlement conditions. Thus, the staff needed additional information for concluding that the program (LRA Section B.2.1.26) will be capable of managing thermal aging embrittlement of the RWCU CASS pump casings.

By letter dated May 18, 2012, the staff issued RAI 3.1.1.38-1.1, requesting the applicant to justify why the applicant's opportunistic inspections and inspection method are sufficient to manage loss of fracture toughness of the pump casings through timely detection of a flaw before it grows to the size that can lead to rapid unstable crack propagation caused by thermal aging embrittlement. The staff also requested that as part of the response, the applicant clarify which type of visual inspection method (e.g., EVT-1, VT-1 or VT-3) will be used to detect flaws in the components and justify why the performance of these visual inspections on an opportunistic basis is considered to be capable of detecting and resolving a flaw before unstable crack propagation in the components (e.g., the basis for concluding that the visual inspection method and frequency will be capable of detecting and resolving a flaw smaller than the critical crack size of the component under reduced fracture toughness conditions, as induced by thermal aging embrittlement). In addition, the staff requested that the applicant justify why the applicant's use of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of fracture toughness of these pump casings is not identified as an enhancement to the "scope of program" element of GALL Report AMP XI.M38.

In its response dated May 31, 2012, the applicant clarified that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is a new program and that LRA Section A.2.1.26, which provides the UFSAR supplement for this program, was revised to specifically include aging management for loss of fracture toughness and cracking as additional aging effects for the program as part of its response to RAI B.2.1.26-1 within the letter dated February 15, 2012. The applicant also indicated that GALL Report AMP XI.M38 is used to manage cracking in stainless steel piping and piping components, as specified in GALL Report item VII.H2.AP-128.

In addition, the applicant indicated that the inspections of the ASME Code, Class 3, pump casings will be performed using VT-3 method, in a consistent manner with the inspection method specified by ASME Code, Section XI, Table IWB-2500-1 for Class 1 pump casings. The applicant further indicated GALL Report item IV.C1.R-08 addresses aging management of loss of fracture of toughness due the thermal aging embrittlement in ASME Code Class 1 CASS pump casings and valve bodies that are exposed to the reactor coolant at temperatures greater than 482 °F. GALL Report item IV.C1.R-08 recommends that GALL Report AMP XI.M1, "ASME Code Section XI, Inservice Inspection, Subsections IWB, IWC, and IWD," be used to manage this aging effect.

In its response, the applicant indicated that GALL Report item IV.C1.R-08 clarifies that for pump casings and valve bodies, screening for susceptibility to thermal aging is not necessary and the ASME Code Section XI inspection requirements are sufficient for managing the effects of loss of fracture toughness caused by thermal aging embrittlement of Class 1 CASS pump casings and valve bodies. Furthermore, the applicant indicated that since ASME Code Section XI does not include an internal inspection requirement for Class 3 pump casings, the use of the opportunistic inspections specified in the applicant's program is sufficient to manage loss of fracture toughness of the RWCU CASS pump casings.

In its review, the staff confirmed that the applicant's response to RAI B.2.1.26-1, dated February 15, 2012, includes the revised UFSAR supplement that clarifies loss of fracture toughness is one of the aging effects that are managed by the applicant's Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff also finds that the applicant's revision to the UFSAR supplement is adequate because this revision clarifies that loss of fracture toughness is one of the aging effects that are managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program.

The staff further noted that that the VT-3 method, which the applicant's inspections will use for the Class 3 pump casings, is the same method specified in ASME Code Section XI, Table IWB-2500-1 for Class 1 pump casings. However, the applicant's response did not clearly address justification as to why applicant's opportunistic inspections would be adequate to manage the aging effect of the RWCU CASS pump casings. Therefore, the staff required additional information to further evaluate the adequacy of the opportunistic inspections for the aging management.

By letter dated June 12, 2012, the staff issued RAI 3.1.1.38-1.2, requesting that the applicant provide results from any inspection(s) that have been performed on the CASS pump casings including when the inspection(s) were completed. The staff also requested that based on the history and results of the previous inspections, the applicant justify why the aging management would not need to ensure the following inspections of the RWCU pump casings: (1) an inspection of the representative pump casing of each unit before the period of extended operation, and (2) at least an inspection of the representative pump casing of each unit during the period of extended operation.

In its response dated June 19, 2012, the applicant stated that the maintenance procedure for disassembly of the RWCU pumps includes a step to examine the casing interior for evidence of defects such as cracks, localized wear or pitting and damaged machined surfaces. The applicant also indicated that the RWCU CASS pumps were last inspected during the conduct of maintenance that required pump disassembly between 2001 and 2003. The applicant further indicated that none of the inspections identified pump casing degradation. Since ASME Code, Section XI does not include requirements to perform internal inspections of Class 3 pump casings, these inspections were not the examinations specified in ASME Code, Section XI.

In addition, the applicant provided the following information in terms of the service characteristics and conditions of the RWCU CASS pump casings:

- These RWCU pumps with CASS casings are infrequently in service. The original design included three 50 percent capacity RWCU CASS pumps on each unit. The "A" RWCU pumps on both LGS units were replaced in the 1999–2001 timeframe with 100 percent capacity carbon steel pumps that use a different design that has proven to be very reliable.
- Since 2001, the CASS "B" and "C" pumps have been normally valved out of service, and are operated very infrequently, only when the "A" RWCU pump is not available. Run time data are not collected on these pumps, but the system engineer can only recall the "B" and "C" pumps being used once caused by "A" pump unavailability during power operations. This instance was on LGS Unit 1 for approximately 6 weeks in 2006."

- Most of the "B" and "C" pump operating time expected in the future is during refueling outages at operating temperature less than 212 °F when maintenance activities take the "A" pump out of service. These pumps are not likely to experience thermal aging embrittlement before or during the period of extended operation since thermal aging embrittlement is applicable to components exposed to operating temperatures greater than 482 °F, they operated at these temperatures for only approximately 15 years, and from 2001 through the period of extended operation the CASS pumps are expected to be normally out of service at ambient temperature.

In its review, the staff noted that the applicant inspected the RWCU CASS pump casings as part of maintenance between 2001 and 2003 and the inspections did not identify any pump casing degradation. The applicant also clarified that the CASS RWCU "B" and "C" pumps are only seldom operated because they serve as standby pumps to the carbon steel "A" RWCU pump. In addition, the applicant clarified that most of the "B" and "C" pump operating time expected in the future is during refueling outages at operating temperatures less than 220 °F because they are normally isolated from the reactor coolant system. The staff finds that the applicant's response is acceptable because the applicant clarified that the previous inspections, which were performed as part of maintenance, did not identify any degradation of the pump casings and the opportunistic inspections specified in the applicant's program is sufficient to manage the potential concern about thermal aging embrittlement of the standby CASS pumps. Therefore, the staff's concern described in RAIs 3.1.1.38-1, 3.1.1.38-1.1, and 3.1.1.38-1.2 is resolved.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. In its review of components associated with item 3.1.1-38 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage loss of fracture toughness using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because (1) the applicant's inspection method for the Class 3 RWCU CASS pump casings is consistent with that specified in ASME Code Section XI, Table IWB-2500-1 for Class 1 pump casings, (2) the applicant's opportunistic inspections associated with the pump maintenance are adequate for aging management in consideration of the service characteristics and conditions of the CASS pump casings (i.e., very infrequent services at temperatures greater than 482 °F as stand-by pumps, and the service temperatures less than 212 degrees F during refueling outages), and (3) the inspections that were performed as part of applicant's maintenance activities indicate the absence of degradation in the pump casings such that the operating experience also supports the adequacy of the applicant's aging management approach.

The staff concludes that for LRA Item 3.1.1 38, 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 during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.1.2.1.5 Loss of Material Due to Pitting and Crevice Corrosion

LRA Table 3.1.1, item 3.1.1-43 addresses nickel-alloy and stainless steel RVI components exposed to reactor coolant, which are being managed for loss of material caused by pitting and crevice corrosion. The LRA credits the BWR Vessel Internals program and the Water Chemistry program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD," and GALL Report AMP XI.M2, "Water Chemistry," to ensure that these aging effects are adequately managed. The associated AMR items cite generic note E, indicating that the LRA AMR is consistent with the GALL Report item for material, environment, and aging effect, but a different AMP is credited.

For those items associated with generic note E, GALL Report AMP XI.M1 recommends using periodic visual, surface, or volumetric examination and leakage testing along with GALL Report AMP XI.M2, which recommends monitoring and controlling known detrimental contaminants in accordance with the recommendations of BWRVIP-130 to manage the aging of this item. In its review of components associated with item 3.1.1-43 for which the applicant cited generic note E, the staff noted that the BWR Vessel Internals program is substituted for the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program because the applicant proposes to manage the aging of nickel-alloy and stainless steel RVI components through ISIs in accordance with component-specific BWRVIP documents that include industry-approved inspection procedures and flaw evaluations. The staff noted that the BWRVIP requires the use of enhanced inspection methods such as EVT-1 or UT, in lieu of the ISI required VT-1 or VT-3 for select components and locations. The staff noted that the applicant's use of its Water Chemistry program is consistent with the recommendations of the GALL Report.

The staff's evaluation of the BWR Vessel Internals and Water Chemistry programs are documented in SER Sections 3.0.3.2.2 and 3.0.3.1.2, respectively. The staff noted that the Water Chemistry program includes controls of chemistry parameters that create an environment not conducive for loss of material to occur.

In its review of components associated with item 3.1.1-43, the staff finds the applicant's proposal to manage aging using the BWR Vessel Internals program and Water Chemistry program acceptable because the BWR Vessel Internals program follows the guidelines recommended by the BWRVIP, which includes specific flaw evaluation and repair recommendations to facilitate post-inspection review; and the applicant's use of the Water Chemistry program creates an environment not conducive for loss of material to occur, and is consistent with the recommendations of the GALL Report.

The staff concludes that 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.6 Cracking Caused by Stress Corrosion Cracking

LRA Table 3.1.1, item 3.1.1-97 addresses stainless steel and nickel alloy piping, piping components, and piping elements greater than or equal to 4 NPS exposed to reactor coolant, which will be managed for cracking caused by SCC and IGSCC. For the AMR items that cite generic note A, the applicant proposes use of the BWR Stress Corrosion Cracking program and Water Chemistry program to manage the aging effect, consistent with the GALL Report.

For LRA Table 3.1.1, item 3.1.1-97 the GALL Report recommends using GALL Report AMP XI.M2, "Water Chemistry," and GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking." GALL Report AMP XI.M2 recommends water chemistry control to manage aging by limiting the concentrations of chemical species known to cause SCC and IGSCC and controlling dissolved oxygen levels to minimize the environmental effect on the aging effect. GALL Report

AMP XI.M7 recommends volumetric examinations of stainless steel and nickel alloy components to detect and manage cracking caused by SCC and IGSCC.

For the AMR item that addresses nickel alloy tubing with generic note E, the LRA credits the Water Chemistry program and One-Time Inspection program to manage the aging effect of the nickel alloy tubing within the HPCI steam flow element. The Water Chemistry program proposes to manage the aging of the components through periodic monitoring of the reactor coolant and control of known detrimental contaminants, such as chlorides, dissolved oxygen, and sulfate. The One-Time Inspection program proposes to manage the aging of the components through a one-time inspection of the representative sample including the lead components most susceptible to aging. The applicant indicated that the One-Time Inspection program will ensure that unacceptable degradation does not occur or will trigger additional actions to maintain the intended function of affected components during the period of extended operation.

In its review, the staff noted that LRA Table 3.1.2-1 (LRA page 3.1-37) relates nickel alloy piping, piping components, and piping elements to LRA Table 3.1.1, item 3.1.1-97, indicating that these components are subject to cracking caused by SCC and IGSCC and the aging effect is managed by the One-Time Inspection program and the Water Chemistry program. The staff also noted that the One-Time Inspection program does not include periodic inspections that are included in the BWR Stress Corrosion Cracking program or the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. The LRA does not clearly indicate whether any of these nickel alloy components addressed under item 3.1.1-97 is included in the scope of the BWR Stress Corrosion Cracking program or the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program.

By letter dated April 30, 2012, the staff issued RAI 3.1.1.97-1, requesting the applicant to provide information to clarify why any of these nickel alloy components are not included in the scope of the BWR Stress Corrosion Cracking program or the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, which includes periodic inspections (e.g., describe pipe size, location, and ASME Code classes of the components and the coolant temperature to which these components are exposed). The staff also requested that the applicant justify why the One-Time Inspection program, which does not include periodic inspections, is adequate to manage cracking caused by SCC and IGSCC of the nickel alloy components. The staff further requested that as part of the response, the applicant clarify if SCC or IGSCC has been observed in these components in order to demonstrate that applicant's operating experience supports the adequacy of the One-Time Inspection program to manage the aging effect.

In its response dated May 7, 2012, the applicant stated that the only nickel alloy components described in LRA Table 3.1.1, item 3.1.1-97 are tubing sections within the HPCI steam supply flow elements. The applicant also indicated that these tubing sections are 7/8-inch outer diameter and are completely contained within the flow element housings. In addition, the applicant stated that these flow elements are within the ASME Code Class 1 section of the HPCI steam supply piping and the nickel alloy tubing is exposed to a reactor coolant environment at nominal 1,035 psig and 550 °F. The applicant stated that since the tubing is internal to the flow element housings, it is not a pressure-retaining component within the context of ASME Code, Section XI, and is not within the scope of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. The applicant indicated that because the tubing sections are less than 4 NPS, these components are not included in the scope of the

BWR Stress Corrosion Cracking program. The staff confirmed that tubing less than 4 NPS is not included in the scope of the BWR Stress Corrosion Cracking program.

In its response, the applicant also indicated that its review of plant-specific operating experience did not identify any indication of aging (cracking or loss of material) of the nickel alloy tubing within the flow elements. The applicant further explained that the "detection of aging effects" program element of GALL Report AMP XI.M32, indicates that the One-Time Inspection program includes inspection and testing techniques that have a demonstrated history of effectiveness in managing aging effects including cracking and loss of material. In addition, the applicant indicated that its Water Chemistry and One-Time Inspection programs are consistent with GALL Report AMPs XI.M2 and XI.M32, respectively, as described in LRA Sections B.2.1.2 and B.2.1.22; therefore, the One-Time Inspection program in conjunction with the Water Chemistry program is adequate to manage cracking of the nickel alloy tubing sections within the HPCI steam supply flow elements.

The staff finds the applicant's response acceptable because the applicant confirmed that the nickel alloy tubing sections are 7/8-inch outer diameter within the flow element pressure boundary and these components are not subject to the periodic volumetric examinations specified in the BWR Stress Corrosion Cracking program and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. In addition, the applicant confirmed that the plant-specific operating experience did not identify any indication of cracking or loss of material of these components, which also supports the adequacy of the applicant's proposal to use the One-Time inspection program for the aging management. Therefore, the staff's concern in RAI 3.1.1.97-1 is resolved.

For the AMR item that addresses stainless steel pump casing and valve bodies with generic note E, the LRA credits the Water Chemistry program and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program to manage the aging effect of these components. The Water Chemistry program proposes to manage the aging of the components through periodic monitoring and control of the reactor coolant chemistry to mitigate environmental effect on SCC and IGSCC. The ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes periodic visual and volumetric examinations to manage aging. For example, the 2001 edition through the 2003 addenda of ASME Code, Section XI, Subsection IWB, Table IWB-2500-1 specifies visual VT-1 examination of pump casing welds and visual VT-3 examination of pump casing internal surfaces. ASME Code, Section XI, Table IWB-2500-1 also specifies volumetric examination of valve body welds for the valves, NPS 4 or larger.

In its review, the staff noted that LRA Table 3.1.2-1 (LRA page 3.1-40) relates the CASS valve body to LRA item 3.1.1-97, indicating that this component type is subject to cracking caused by SCC and IGSCC. The LRA also indicates that the aging effect is managed by the Water Chemistry program and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program.

As addressed above, Table IWB-2500-1 of the 2001 edition through the 2003 addenda of the ASME Code Section XI requires that the valve body welds of valves, NPS 4 or larger, should be examined using volumetric examination in accordance with Examination Category B-M-1, item No. B12.40. The staff further noted that Appendix VIII, Supplement 9 of the 2001 edition with 2002 and 2003 addenda of the ASME Code Section XI, Division 1 indicates that the qualification requirements for ultrasonic examination of cast austenitic piping welds are in the course of preparation. However, the LRA does not provide the following information necessary to determine the inspection method in accordance with the ASME Code Section XI: (1) the size of the CASS valve bodies and (2) whether the valve bodies have a weld.

By letter dated April 30, 2012, the staff issued RAI 3.1.1.97-2, requesting the applicant to provide the information to clarify the size of the CASS valve bodies and whether the valve bodies have a weld that requires volumetric examination. The staff also requested that if the valve bodies contain welds, the applicant describe the inspection method that will be used to detect and manage cracking in these components and justify why the inspection method is adequate to detect and manage cracking caused by SCC and IGSCC.

In its response, dated May 7, 2012, the applicant provided the size data for the CASS valve bodies and confirmed that all of the CASS valve bodies are greater than NPS 4. The applicant also indicated that none of these valve bodies have welds as described in ASME Code Section XI Table IWB-2500-1, Examination Category B-M-1 and referenced Figure IWB-2500-17. The applicant further indicated that since none of the CASS valve bodies have welds, volumetric examination per ASME Code Section XI, Table IWB-2500-1, Examination Category B-M-1, item No. B12.40 is not required for these valves.

The staff finds that the applicant's response acceptable because the applicant confirmed that all of these CASS valve bodies are greater than NPS 4 and none of these valve bodies have welds such that volumetric examination would be required in accordance with ASME Code Section XI, item No. B12.40. The staff also noted that ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes visual examination of the internal surfaces of these valve bodies as specified in item No. B12.50, which is adequate to detect and manage cracking of these valve bodies. The staff's concern in RAI 3.1.1.97-2 is resolved.

The staff's evaluations of the Water Chemistry program and One-Time Inspection program are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.12, respectively. In its review of the nickel alloy tubing associated with item 3.1.1-97, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry program and One-Time Inspection program acceptable because the Water Chemistry program limits the concentrations of chemical species known to cause SCC and IGSCC and controls the dissolved oxygen level to minimize the environmental effect on aging, and the One-Time Inspection program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry program such that it is ensured to adequately manage cracking caused by SCC and IGSCC of these components.

In addition, the staff's evaluation of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is documented in SER Section 3.0.3.1.1. In its review of the stainless steel pump casing and valve bodies associated with item 3.1.1-97, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry program and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program acceptable because the Water Chemistry program limits the concentrations of chemical species known to cause SCC and IGSCC and controls the dissolved oxygen level to minimize the environmental effect on aging as described above, and the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes visual examination of these components, which is adequate to detect and manage cracking caused by SCC and IGSCC of the components.

The staff concludes that for LRA item 3.1.1-97, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.1.7 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed were not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed were not applicable are not applicable to LGS Units 1 and 2.

As discussed in SER Section 3.0.2.2, for those AMRs that the applicant claimed consistency with the GALL Report, the staff evaluated the applicant's claim of consistency. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent.

Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.1.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.1.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the reactor vessel, internals, and RCS components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material caused by general, pitting, and crevice corrosion
- loss of fracture toughness caused by neutron irradiation embrittlement
- cracking caused by SCC and IGSCC
- crack growth caused by cyclic loading
- cracking caused by SCC
- cracking caused by cyclic loading
- loss of material caused by erosion
- cracking caused by SCC and irradiation-assisted SCC
- loss of fracture toughness caused by neutron irradiation embrittlement; change in dimension caused by void swelling; loss of preload caused by stress relaxation; or loss of material caused by wear
- cracking caused by primary water stress corrosion cracking (PWSCC)
- cracking caused by fatigue
- cracking caused by SCC and fatigue

- loss of material caused by wear
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.1.2.2. The staff's review of the applicant's further evaluation follows.

3.1.2.2.1 Cumulative Fatigue Damage

LRA Section 3.1.2.2.1 addresses the applicant's AMR basis for managing cumulative fatigue damage for the RPV, RVIs, RCPB, and CRD system. The applicant stated that fatigue is a TLAA as defined in 10 CFR 54.3 and these TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). Additional information for these TLAAs is discussed in LRA Section 4.3.

The applicant identified the following items in LRA Table 3.1.1 that are applicable:

> Item 3.1.1-1 – The applicant stated that metal fatigue of steel top head closure studs is a TLAA addressed in LRA Section 4.3.
>
> Item 3.1.1-3 – The applicant stated that metal fatigue of steel, stainless steel, and steel with nickel-alloy reactor internal components is a TLAA addressed in LRA Section 4.3.
>
> Item 3.1.1-4 – The applicant stated that metal fatigue of steel pressure vessel support skirt and attachment welds is a TLAA addressed in LRA Section 4.3.
>
> Item 3.1.1-6 – The applicant stated that metal fatigue of the stainless steel, steel with nickel-alloy or stainless steel cladding, and nickel-alloy RCPB piping, piping components, and piping elements is a TLAA addressed in LRA Section 4.3.
>
> Item 3.1.1-7 – The applicant stated that metal fatigue of steel or stainless steel and nickel-alloy reactor vessel components is a TLAA in LRA Section 4.3.
>
> Item 3.1.1-11 – The applicant stated that metal fatigue of the stainless steel or steel pump and valve closure bolting is a TLAA addressed in LRA Section 4.3.

The staff noted that LRA Table 3.1.1, items 3.1.1-2, 3.1.1-5, 3.1.1-8, 3.1.1-9, and 3.1.1-10 are specifically related to components in a PWR design; therefore, the staff finds it appropriate that the applicant did not address these items in the LRA.

The staff reviewed LRA Section 3.1.2.2.1 against the further evaluation criteria in SRP-LR Section 3.1.2.2.1, which states that fatigue is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with 10 CFR 54.21(c)(1) and SRP-LR Section 4.3. The staff also reviewed the AMR items associated with LRA Section 3.1.2.2.1, and found that the AMR results are consistent with the GALL Report and SRP-LR.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.1.2.2.1 criteria. For those items that apply to LRA Section 3.1.2.2.1, the staff determined that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

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

The staff reviewed LRA Section 3.1.2.2.2 against the following criteria in SRP-LR Section 3.1.2.2.2:

(1) LRA Section 3.1.2.2.2, item 1, which is associated with LRA Table 3.1.1, item 3.1.1-12, addresses loss of material caused by general, pitting, and crevice corrosion in steel PWR steam generator components exposed to secondary feedwater and steam. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and noted that the applicant's units are a BWR design and do not have steam generators; therefore, the staff finds it acceptable.

(2) LRA Section 3.1.2.2.2, item 2, which is associated with LRA Table 3.1.1, item 3.1.1-12, addresses loss of material caused by general, pitting, and crevice corrosion in steel PWR steam generator components exposed to secondary feedwater and steam. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that the item is applicable only to PWRs and noted that the applicant's units are a BWR design and do not have steam generators; therefore, the staff finds it acceptable.

3.1.2.2.3 Loss of Fracture Toughness Due to Neutron Irradiation Embrittlement

The staff reviewed LRA Section 3.1.2.2.3 against the following criteria in SRP-LR Section 3.1.2.2.3:

(1) LRA Section 3.1.2.2.3 item 1, which is associated with LRA Table 3.1.1, item 3.1.1-13, states that these TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1) and that the evaluations are addressed in LRA Section 4.2. This is consistent with SRP-LR Section 3.1.2.2.3 item 1 and is, therefore, acceptable. The staff's evaluation of the TLAAs for all ferritic materials with neutron fluence greater than 1×10^{17} n/cm^2 (E > 1 MeV) is documented in SER Section 4.2.

(2) LRA Section 3.1.2.2.3, item 2, which is associated with LRA Table 3.1.1, item 3.1.1-14, addresses carbon or low-alloy steel with stainless steel cladding reactor vessel beltline shell and welds exposed to reactor coolant and neutron flux that will be managed for loss of fracture toughness caused by neutron irradiation embrittlement. In LRA Section 3.1.2.2.3.2, the applicant credits its Reactor Vessel Surveillance program to manage the loss of fracture toughness of the reactor vessel beltline components and welds exposed to a reactor coolant and flux environment. This is an existing program that manages the loss of fracture toughness caused by neutron irradiation embrittlement of the reactor vessel beltline materials in a reactor coolant and neutron flux environment. The program meets the requirements of 10 CFR Part 50, Appendix H, and the Reactor

Vessel Surveillance program is part of the BWRVIP ISP described in BWRVIP-86-A and BWRVIP-116. In addition, the program includes monitoring of plant operating conditions to ensure appropriate steps are taken if reactor vessel exposure conditions are altered, such as the review and updating of 60-year fluence projections to support upper-shelf energy calculations and pressure-temperature limit curves. The LRA states that the Reactor Vessel Surveillance program is consistent with the elements of GALL Report AMP XI.M31, "Reactor Vessel Surveillance."

The criteria in SRP-LR Section 3.1.2.2.3, for item 2 states that loss of fracture toughness caused by neutron irradiation embrittlement could occur in BWR and PWR reactor vessel beltline shell, nozzle, and welds exposed to reactor coolant and neutron flux. The SRP-LR also states that a reactor vessel materials surveillance program monitors neutron irradiation embrittlement of the reactor vessel, and is plant-specific depending on matters such as the composition of limiting materials, availability of surveillance capsules, and projected fluence levels. The SRP-LR further states that specific recommendations for an acceptable AMP are provided in GALL Report AMP XI.M31, "Reactor Vessel Surveillance."

The staff's evaluation of the Reactor Vessel Surveillance program is documented in SER Section 3.0.3.1.11. In its review the staff noted that the applicant's program addresses irradiation embrittlement of the RPV beltline and extended beltline materials through testing that monitors the properties of beltline materials. During its review the staff noted that the Reactor Vessel Surveillance program is consistent with GALL Report AMP XI.M31. Based on its review of components associated with item 3.1.1-14, the staff finds the applicant's use of its Reactor Vessel Surveillance program acceptable because the applicant will continue to use the existing program during the period of extended operation, consistent with its CLB.

Based on the program identified, the staff concludes that the applicant's program meets SRP-LR Section 3.1.2.2.3, item 2, criteria. For those items that apply to LRA Section 3.1.2.2.3, item 2, the staff determines that the LRA is consistent with the GALL Report and that the applicant demonstrated that the effects of aging will be adequately managed so that the intended function(s) will remain consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(3) LRA Section 3.1.2.2.3 item 3, associated with LRA Table 3.1.1, item 3.1.1-15, states that Ductility – Reduction in Fracture Toughness is a plant-specific TLAA for Babcock and Wilcox (B&W) reactor internals. The applicant stated that this item is not applicable because it is associated with PWRs only, specifically, B&W-designed PWRs. The staff confirmed that this item is associated only with B&W-designed PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.4 Cracking Due to Stress Corrosion Cracking and Intergranular Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.4 against the following criteria in SRP-LR Section 3.1.2.2.4:

(1) LRA Section 3.1.2.2.4, associated with LRA Table 3.1.1, items 3.1.1-16 and 3.1.1-39, addresses carbon and stainless steel top head enclosure vessel flange leak detection lines exposed to reactor coolant, which will be managed for cracking by the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and

One-Time Inspection of ASME Code Class 1 Small-Bore Piping programs. The criteria in SRP-LR Section 3.1.2.2.4, item 1, state that cracking caused by SCC and IGSCC could occur in stainless steel and nickel alloy BWR top head enclosure vessel flange leak detection lines. The SRP-LR also states that a plant-specific AMP should be evaluated because existing programs may not be capable of mitigating or detecting cracking caused by SCC or IGSCC.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that the top head enclosure vessel flange leak detection lines are stainless steel ASME Code Class 1 piping that also have the potential for cracking caused by thermal, mechanical, and vibratory loading mechanisms. As such, the applicant explained that instead of LRA Table 3.1.1, item 3.1.1-16, it used item 3.1.1-39, which credits the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and One-Time Inspection of ASME Code Class 1 Small-Bore Piping programs to manage cracking. The applicant also indicated that the stainless steel portions of the lines are welded to short sections of carbon steel piping, which in turn are welded to nozzles on each flange. Cracking of the carbon steel sections is also managed by these three AMPs. The applicant further stated that the Water Chemistry program will monitor and control water chemistry to prevent or mitigate cracking; periodic examinations, in accordance with the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, will identify, evaluate, and manage the effects of cracking; and these examinations will be supplemented by a one-time inspection under the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program.

The staff's evaluation of the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and One-Time Inspection of ASME Code Class 1 Small-Bore Piping programs is documented in SER Sections 3.0.3.1.1, 3.0.3.1.2, and 3.0.3.1.14, respectively. The staff confirmed from the UFSAR that the carbon and stainless steel top head enclosure vessel flange leak detection lines are ASME Code, Class 1, and 1-inch NPS. SRP-LR Table 3.1-1 summarizes AMPs evaluated in the GALL Report Chapter IV for the reactor vessel, internals, and reactor coolant system. Item 39 in this table specifically addresses steel, stainless steel, or steel with stainless steel cladding ASME Code Class 1 piping, fittings, and branch connections less than 4 inches NPS exposed to reactor coolant, which are subject to cracking caused by stress corrosion, intergranular stress corrosion (stainless steel only), and thermal, mechanical, and vibratory loading. The applicant's AMR for the top head enclosure vessel flange leak detection lines is consistent with SRP-LR Table 3.1-1, item 39, because the lines are ASME Code Class 1 and less than 4 inches NPS, and because they are made of materials, in a service environment, and subject to the same aging effect as described in SRP-LR Table 3.1-1, item 39. This item credits aging management through GALL Report AMPs XI.M1, XI.M2, and XI.M35 and recommends no further evaluation. As discussed in SER Sections 3.0.3.1.1, 3.0.3.1.2, and 3.0.3.1.14, the staff determined that the applicant's AMPs are each consistent with the corresponding GALL Report programs. Specifically, the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program is consistent with GALL Report AMP XI.M1, the Water Chemistry program is consistent with GALL Report AMP XI.M2, and the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program is consistent with GALL Report AMP XI.M35. As such, the applicant's use of SRP-LR Table 3.1-1, item 39, is consistent with the GALL Report.

In its review of components associated with LRA Table 3.1.1, items 3.1.1-16 and 3.1.1-39, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage cracking using the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD; Water Chemistry; and One-Time Inspection of ASME Code Class 1 Small-Bore Piping programs is acceptable because these programs will mitigate and detect cracking caused by SCC and IGSCC. The Water Chemistry program will mitigate cracking through the control of water chemistry. The ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program will detect cracking through periodic visual examinations conducted during system leakage tests, as per ASME Code, Section XI, Table IWB-2500-1, Examination Category B-P, "All Pressure Retaining Components." In addition, cracking will be detected through the volumetric or destructive examinations implemented in accordance with the One-Time Inspection of ASME Code Class 1 Small-Bore Piping program. This approach is consistent with SRP-LR Table 3.1-1, item 39.

In addition, the staff notes that, under the applicant's current ISI program, the visual examinations during system leakage tests are conducted at reduced pressure before reactor cavity draining during each refueling outage. Performance of the examinations in this manner is by an NRC-approved relief request; however, this request is only valid for the third ISI interval. Therefore, the future use of this approach to manage aging in subsequent ISI intervals, which encompass the period of extended operation, will require subsequent NRC approval. If such a request is not approved for any subsequent inservice inspection interval, then the visual examinations must be performed at normal pressure, as required by 10 CFR 50.55a and ASME Code Section XI.

Based on the programs identified, the staff determines that the applicant's programs meet SRP-LR Section 3.1.2.2.4, item 1, criteria. For those items associated with LRA Section 3.1.2.2.4, item 1, the staff concludes that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

(2) LRA Section 3.1.2.2.4.2, which is associated with LRA Table 3.1.1, item 3.1.1-17, addresses SCC and IGSCC for stainless steel BWR isolation condenser components exposed to reactor coolant. The applicant stated that this item is not used because its design does not use an isolation condenser. The staff reviewed the Units 1 and 2 UFSAR and confirmed that the design of the applicant's units does not include an isolation condenser; therefore, the staff finds the applicant's review result acceptable.

3.1.2.2.5 Crack Growth Caused by Cyclic Loading

LRA Section 3.1.2.2.5 refers to Table 3.1.1, item 3.1.1-18, and addresses crack growth caused by cyclic loading. The applicant stated that this aging effect is not applicable to LGS, which is a BWR.

SRP-LR Section 3.1.2.2.5 states that crack growth caused by cyclic loading could occur in reactor vessel shell forgings clad with stainless steel using a high-heat-input welding process. SRP-LR Table 3.1-1 identifies item 18 as applicable to PWRs. The staff confirmed that SRP-LR Section 3.1.2.2.5 is not applicable to LGS because it is a BWR, and the staff guidance in this SRP-LR section is only applicable to PWR-designed reactor vessel shells fabricated of SA508-Cl forgings clad with stainless steel using a high-heat-input welding process.

Based on the information above, the staff concludes that the staff's guidance criteria of SRP-LR Section 3.1.2.2.5 do not apply to LGS Units 1 and 2 because the guidance is applicable to PWRs.

3.1.2.2.6 Cracking Caused by Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.6 against the criteria in SRP-LR Section 3.1.2.2.6.

(1) LRA Section 3.1.2.2.6, item 1, which is associated with LRA Table 3.1.1, item 3.1.1-19, addresses cracking caused by SCC in PWR stainless steel reactor vessel flange leak detection lines and bottom-mounted instrument guide tubes exposed to reactor coolant. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

(2) LRA Section 3.1.2.2.6, item 2, which is associated with LRA Table 3.1.1, item 3.1.1-20, addresses cracking caused by SCC in Class 1 PWR CASS reactor coolant system piping, piping components, and piping elements. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

Based on the above, the staff concludes that SRP-LR Section 3.1.2.2.6 criteria do not apply.

3.1.2.2.7 Cracking Caused by Cyclic Loading

LRA Section 3.1.2.2.7, which is associated with LRA Table 3.1.1, item 3.1.1-21, addresses cracking caused by cyclic loading for steel and stainless steel BWR isolation condenser components exposed to reactor coolant. The applicant stated that this item is not used because its design does not use an isolation condenser. The staff reviewed the LGS Units 1 and 2 UFSAR and confirmed that its designs do not include an isolation condenser; therefore, the staff finds the applicant's review result acceptable.

3.1.2.2.8 Loss of Material Caused by Erosion

LRA Section 3.1.2.2.8, which is associated with LRA Table 3.1.1, item 3.1.1-22, addresses loss of material caused by erosion in PWR steam generator feedwater impingement plates and supports exposed to secondary feedwater. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.9 Cracking Caused by Stress Corrosion Cracking and Irradiation-Assisted Stress Corrosion Cracking

LRA Section 3.1.2.2.9, which is associated with LRA Table 3.1.1, item 3.1.1-23, addresses cracking caused by SCC, and irradiation-assisted SCC could occur in inaccessible locations for stainless steel and nickel-alloy primary and expansion PWR reactor vessel internal components. The applicant stated that this item is not applicable because the associated item in LRA

Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.10 Loss of Fracture Toughness Caused by Neutron Irradiation Embrittlement, Change in Dimension Because of Void Swelling, Loss of Preload Because of Stress Relaxation, or Loss of Material Because of Wear

LRA Section 3.1.2.2.10, which is associated with LRA Table 3.1.1, item 3.1.1-24, addresses loss of fracture toughness caused by neutron irradiation embrittlement, change in dimension caused by void swelling, loss of preload caused by stress relaxation, or loss of material caused by wear, which could occur in inaccessible locations for stainless steel and nickel-alloy primary and expansion PWR reactor vessel internal components. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.11 Cracking Caused by Primary Water Stress Corrosion Cracking

The staff reviewed LRA Section 3.1.2.2.11 against the criteria in SRP-LR Section 3.1.2.2.11.

(1) LRA Section 3.1.2.2.11, item 1, which is associated with LRA Table 3.1.1, item 3.1.1-25, addresses foreign operating experience in steam generators with a similar design to that of Westinghouse Model 51 which has identified extensive cracking caused by PWSCC in steam generator divider plate assemblies fabricated of Alloy 600 and/or the associated Alloy 600 weld materials, even with proper primary water chemistry (EPRI TR-1014982). The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

(2) LRA Section 3.1.2.2.11, item 2, which is associated with LRA Table 3.1.1, item 3.1.1-25, addresses cracking caused by PWSCC that could occur in steam generator nickel alloy tube-to-tube sheet welds exposed to reactor coolant. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

Based on the above, the staff concludes that SRP-LR Section 3.1.2.2.11 criteria do not apply.

3.1.2.2.12 Cracking Caused by Fatigue

LRA Section 3.1.2.2.12, which is associated with LRA Table 3.1.1, item 3.1.1-26, addresses cracking caused by fatigue as an aging effect that can occur for the lower flange weld in the core support barrel assembly, fuel alignment plate in the upper internals assembly, and core support plate lower support structure in PWR internals designed by Combustion Engineering. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.13 Cracking Caused by Stress Corrosion Cracking and Fatigue

LRA Section 3.1.2.2.13, which is associated with LRA Table 3.1.1, item 3.1.1-27, addresses cracking caused by SCC and fatigue that could occur in nickel alloy control rod guide tube assemblies, guide tube support pins exposed to reactor coolant, and neutron flux. The applicant stated that this item is not applicable because the associated item in LRA Table 3.1.1 is applicable to PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.14 Loss of Material Because of Wear

LRA Section 3.1.2.2.14, associated with LRA Table 3.1.1, item 3.1.1-28, addresses loss of material caused by wear in nickel alloy control rod guide tube assemblies, guide tube support pins, and Zircaloy-4 in-core instrumentation lower thimble tubes exposed to reactor coolant and neutron flux. The applicant stated that this item is not applicable because it is associated with PWRs only. The staff confirmed that this item is associated only with PWRs and, therefore, finds the applicant's claim acceptable.

3.1.2.2.15 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.1.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.1.2-1 through 3.1.2-3, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.1.2-1 through 3.1.2-3, the applicant, via notes F through J, indicated that the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether 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. The staff's evaluation is documented in the following sections.

3.1.2.3.1 Reactor Coolant Pressure Boundary – Summary of Aging Management Review – LRA Table 3.1.2-1

The staff reviewed LRA Table 3.1.2-1, which summarizes the results of AMR evaluations for the RCPB component groups.

In LRA Table 3.1.2-1, the applicant stated that CASS main steam flow elements exposed to steam is being managed for loss of material by a TLAA. The AMR item cites generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1), and the staff's evaluation of the TLAA for this item is documented in SER Section 4.6.4.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.1.2.3.2 Reactor Pressure Vessel – Summary of Aging Management Review – LRA Table 3.1.2-2

The staff reviewed LRA Table 3.1.2-2, which summarizes the results of AMR evaluations for the RPV component groups.

In LRA Table 3.1.2-2, the applicant stated that for low-alloy steel and carbon or low-alloy steel with stainless steel cladding RPV components exposed to uncontrolled indoor air there is no aging effect and no AMP is proposed. The AMR items cite generic note H. Items associated with RPV components and generic note H cite plant-specific note 2, which states that the components have external temperatures greater than 212 °F and, therefore, are not exposed to wetting caused by condensation and moisture accumulation.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that moisture accumulation is not expected to occur on components with temperatures above the atmospheric dew point, which is necessarily less than the boiling point of water, 212 °F. The staff finds the applicant's proposal acceptable based on its review of ASM Handbook, Volume 13A, 2003, "Atmospheric Corrosion," which states that the atmospheric corrosion reaction will not occur without the presence of an electrolyte (i.e., moisture).

In LRA Table 3.1.2-2, the applicant stated that the N16 nozzles exposed to reactor coolant and neutron flux are being managed for loss of fracture toughness by a TLAA. The AMR item cites generic note H, which indicates that the aging effect is not addressed in the GALL Report for this component, material, and environment combination. TLAAs are evaluated in accordance with 10 CFR 54.21(c)(1), and the staff's evaluation of the TLAA for this item would have been documented in SER Section 4.2.2, but because the N16 nozzles and the associated welds are made from austenitic material (nickel alloy 600), no significant loss of fracture toughness is expected.

In LRA Table 3.1.2-2, the applicant stated that the nickel alloy reactor vessel internal attachments exposed to reactor coolant will be managed for loss of material by the BWR Vessel ID Attachment Welds. The AMR item cite generic note H. Items associated with nickel alloy reactor vessel internal attachments in Table 3.1.2-2 cite plant-specific note 5, which states that loss of material caused by wear is applicable to the steam dryer support brackets as identified by operating experience review.

The staff noted that this material and environment combination is identified in the GALL Report, which addresses nickel alloy reactor vessel internal attachments exposed to reactor coolant and recommends One-Time Inspection and Water Chemistry programs to manage loss of material; however, the applicant has also identified BWR Vessel ID Attachment Welds program to manage loss of material. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in AMR items in LRA Table 3.1.2-2.

The staff's evaluation of the BWR Vessel ID Attachment Welds program is documented in SER Section 3.0.3.1.4. The staff noted that the program includes inspections of reactor vessel internal attachments in accordance with ASME Code, Section XI, Subsection IWB, Examination Category B-N-2, which allows the use of visual VT-3 examination to determine the general mechanical and structural condition of the component, consistent with the GALL Report. During its review, the staff noted that loss of material is not explicitly addressed in GALL Report AMP XI.M4 or BWRVIP-48-A; therefore, it was not clear to the staff whether the VT-3 inspection is an appropriate and effective inspection method to identify loss of material of the steam dryer support brackets. By letter dated November 18, 2011, the staff issued RAI B.2.1.4-1 requesting the applicant justify that the VT-3 inspection is an appropriate and effective inspection method to identify loss of material caused by wear for the steam dryer support brackets. In its response dated December 7, 2011, the applicant explained that BWRVIP48-A refers to ASME Code Section XI, Subsection IWB-3520 for acceptance criteria and corrective actions for wear are in accordance with ASME Code Section XI, Subsection IWB-3140. The staff's review of the applicant's response to RAI B.2.1.4-1 is documented in SER Section 3.0.3.1.4.

The staff finds the applicant's proposal to manage aging using the BWR Vessel ID Attachment Welds program acceptable because the program includes augmented inspections with a demonstrated capability of detecting loss of material and establishes acceptance criteria and corrective actions consistent with ASME Code, Section XI, which implement measures to mitigate or prevent the aging effect caused by loss of material. In addition, the staff finds the applicant's use of this program conservative because it is being credited to manage loss of material in addition to the GALL Report recommendations.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.1.2.3.3 Reactor Vessel Internals- Summary of Aging Management Review – LRA Table 3.1.2-3

The staff reviewed LRA Table 3.1.2-3, which summarizes the results of AMR evaluations for the RVI component groups.

In LRA Table 3.1.2-3, the applicant stated that there is a TLAA for stainless steel core plate bolts exposed to reactor coolant and neutron flux, which cite generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.6.3, for this component and material. The staff's evaluation of the TLAA for the core plate bolts is documented in SER Section 4.6.3.

In LRA Table 3.1.2-3, the applicant stated that Alloy X-750 jet pump assemblies: thermal sleeve inlet header, riser brace arm, holddown beams, inlet elbow, mixing assembly, diffuser castings, slip joint clamp, and wedge assemblies exposed to reactor coolant and neutron flux will be managed for loss of material by the BWR Vessel Internals program. The AMR item cites generic note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the LRA, which states that the components are also being managed for cracking, cumulative fatigue damage, loss of fracture toughness, and loss of preload, BWRVIP-41, Revision 2, and the GALL Report, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the BWR Vessel Internals program is documented in SER Section 3.0.3.2.2. The staff noted that high-strength, Alloy X-750 material is used to minimize the effects of wear, but cannot prevent wear from occurring in the jet pump wedge assemblies caused by excessive vibration that is sometimes present in the assemblies. The staff also noted that the GALL Report recommends that stainless steel and nickel alloy jet jump components (GALL AMR item IV.B1.RP-377) exposed to reactor coolant be managed for loss of material caused by wear with the BWR Vessel Internals program; the irradiation effect of the neutron flux does not influence the loss of material caused by wear so that this item is essentially the same as the GALL Report item.

The staff finds the applicant's proposal to manage aging using the BWR Vessel Internals program acceptable because the VT-1 visual inspections described in BWRVIP-41 are capable of resolving the evidence for mechanical wear of the components and the BWRVIP-41 report recommends frequent inspections that are able to monitor the performance of the jet pump. In addition, the GALL Report includes the same program to manage loss of material caused by wear for stainless steel and nickel alloy jet pump components in a similar environment.

In LRA Table 3.1.2 3, the applicant stated that loss of preload due to stress relaxation and irradiation-assisted creep is an applicable aging effect for the following jet pump assembly components that are exposed to a reactor coolant and neutron flux environment: (a) jet pump auxiliary spring wedge assemblies, which are wedged mechanical connections made of Inconel X-750, (b) jet pump restrainer bracket pad repair clamps, which are bolted/screwed mechanical connections made of Type 304 austenitic stainless steel, and (c) jet pump assembly inlet-mixer to diffuser slip joint clamps, which are bolted/screwed mechanical connections made of Inconel X-750 materials. For these components, the applicant cited generic note H and stated that it evaluated the loss of preload as TLAAs in LRA Section 4.6. As part of the TLAA evaluation for the jet pump restrainer bracket pad repair clamps, the LRA also credits the BWR Vessel Internals Program for managing loss of preload. However, in its January 24, 2012, response to RAI 4.6.9 1, the applicant revised the AMR item for the jet pump restrainer bracket pad repair clamps. Instead of managing the aging effect under the BWR Vessel Internals Program, the applicant stated that it re-evaluated the TLAA to show that the existing design analysis will remain valid through the period of extended operation; thus, no AMP is credited for acceptance of the TLAA in accordance with the 10 CFR 54.21(c)(1) criteria.

The staff verified that the information provided by the applicant is consistent with the design basis information for the jet pump assembly components in UFSAR Section 4.5.2. The staff also confirmed that LRA Section 4.6 includes the applicable TLAAs for the jet pump auxiliary spring wedge assembly, jet pump restrainer bracket pad repair clamps, and jet pump assembly inlet-mixer to diffuser slip joint clamps, as documented in LRA Sections 4.6.5, 4.6.6, and 4.6.9, respectively. The staff's evaluations of the TLAAs for these components are documented in SER Sections 4.6.5, 4.6.6, and 4.6.9, respectively.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.1.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the reactor vessel, internals, and RCS components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2 Aging Management of Engineered Safety Features Systems

This SER section documents the staff's review of the applicant's AMR results for the engineered safety features systems components and component groups of:

- containment atmosphere control
- CS
- HPCI
- reactor core isolation cooling
- RHR
- standby gas treatment

3.2.1 Summary of Technical Information in the Application

LRA Section 3.2 provides AMR results for the ESF systems components and component groups. LRA Table 3.2.1, "Summary of Aging Management Programs for Engineered Safety Features Evaluated in Chapter V of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the ESF systems components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs.
The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.2.2 Staff Evaluation

The staff reviewed LRA Section 3.2 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the ESF systems components within the scope of license renewal and subject to an AMR, 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 conducted a review of AMRs to ensure the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's evaluation are documented in SER Section 3.2.2.1.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.2.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.2.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.2.2.3.

For SSCs the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to verify the applicant's claims.

Table 3.2-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.2 and addressed in the GALL Report.

Table 3.2-1 Staff Evaluation for Engineered Safety Features Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, steel piping, piping components, and piping elements exposed to treated water (borated) (3.2.1-1)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation. See the SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.2.2.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with stainless steel cladding) pump casings exposed to treated water (borated) (3.2.1-2)	Loss of material caused by cladding breach	A plant-specific aging management program is to be evaluated Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	Yes	NA	Not applicable to BWRs (see SER Section 3.2.2.2.2)
Stainless steel partially-encased tanks with breached moisture barrier exposed to raw water (3.2.1-3)	Loss of material caused by pitting and crevice corrosion	A plant-specific aging management program is to be evaluated for pitting and crevice corrosion of tank bottom because moisture and water can egress under the tank caused by cracking of the perimeter seal from weathering.	Yes	NA	Not applicable to BWRs (see SER Section 3.2.2.2.3(1))
Stainless steel piping, piping components, and piping elements; tanks exposed to air-outdoor (3.2.1-4)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	NA	Not applicable to LGS (see SER Section 3.2.2.2.3(2))
Stainless steel orifice (miniflow recirculation) exposed to treated water (borated) (3.2.1-5)	Loss of material caused by erosion	A plant-specific aging management program is to be evaluated for erosion of the orifice caused by extended use of the centrifugal HPSI pump for normal charging. See LER 50-275/94-023 for evidence of erosion.	Yes	NA	Not applicable to BWRs (see SER Section 3.2.2.2.4)
Steel drywell and suppression chamber spray system (internal surfaces): flow orifice; spray nozzles exposed to air-indoor, uncontrolled (internal) (3.2.1-6)	Loss of material caused by general corrosion; fouling that leads to corrosion	A plant-specific aging management program is to be evaluated	Yes	NA	Not applicable to LGS (see SER Section 3.2.2.2.5)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements; tanks exposed to air-outdoor (3.2.1-7)	Cracking caused by stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	NA	Not applicable to LGS (see SER Section 3.2.2.2.6)
Aluminum, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-8)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Steel external surfaces, bolting exposed to air with borated water leakage (3.2.1-9)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	NA	Not applicable to BWRs (see SER Section 3.2.1.1)
CASS piping, piping components, and piping elements exposed to treated water (borated) >250 °C (>482 °F), treated water >250 °C (>482 °F) (3.2.1-10)	Loss of fracture toughness caused by thermal aging embrittlement	Chapter XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Steel piping, piping components, and piping elements exposed to steam, treated water (3.2.1-11)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Flow Accelerated Corrosion	Consistent with the GALL Report
Steel, high-strength closure bolting exposed to air with steam or water leakage (3.2.1-12)	Cracking caused by cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Steel; stainless steel bolting, closure bolting exposed to air-outdoor (external), air-indoor, uncontrolled (external) (3.2.1-13)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel closure bolting exposed to air with steam or water leakage (3.2.1-14)	Loss of material caused by general corrosion	Chapter XI.M18, "Bolting Integrity"	No	NA	See SER Section 3.2.2.1.1

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy, nickel alloy, steel; stainless steel, stainless steel, steel; stainless steel bolting, closure bolting exposed to any environment, air-outdoor (external), raw water, treated borated water, fuel oil, treated water, air-indoor, uncontrolled (external) (3.2.1-15)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report (see SER Section 3.2.2.1)
Steel containment isolation piping and components (internal surfaces), piping, piping components, and piping elements exposed to treated water (3.2.1-16)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry, One-Time Inspection, and Bolting Integrity	Consistent with the GALL Report (see SER Section 3.2.2.1.2)
Aluminum, stainless steel piping, piping components, and piping elements exposed to treated water (3.2.1-17)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry, One-Time Inspection, and Bolting Integrity	Consistent with the GALL Report (see SER Section 3.2.2.1.3)
Stainless steel containment isolation piping and components (internal surfaces) exposed to treated water (3.2.1-18)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	See SER Section 3.2.2.1.1
Stainless steel heat exchanger tubes exposed to treated water (3.2.1-19)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements; tanks exposed to treated water (borated) >60 °C (>140 °F) (3.2.1-20)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with stainless steel or nickel-alloy cladding) safety injection tank (accumulator) exposed to treated water (borated) >60 °C (>140 °F) (3.2.1-21)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements; tanks exposed to treated water (borated) (3.2.1-22)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Steel heat exchanger components, containment isolation piping and components (internal surfaces) exposed to raw water (3.2.1-23)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.2.1-24)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Stainless steel heat exchanger components, containment isolation piping and components (internal surfaces) exposed to raw water (3.2.1-25)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	Consistent with the GALL Report (see SER Section 3.2.2.1.4)
Stainless steel heat exchanger tubes exposed to raw water (3.2.1-26)	Reduction of heat transfer caused by fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	See SER Section 3.2.2.1.1
Stainless steel, steel heat exchanger tubes exposed to raw water (3.2.1-27)	Reduction of heat transfer caused by fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	See SER Section 3.2.2.1.1

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.2.1-28)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-29)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Steel heat exchanger components exposed to closed-cycle cooling water (3.2.1-30)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-31)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Copper alloy heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-32)	Loss of material caused by pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Copper alloy, stainless steel heat exchanger tubes exposed to closed-cycle cooling water (3.2.1-33)	Reduction of heat transfer caused by fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements, heat exchanger components exposed to closed-cycle cooling water (3.2.1-34)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Gray cast iron motor cooler exposed to treated water (3.2.1-35)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching	Consistent with the GALL Report
Gray cast iron piping, piping components, and piping elements exposed to closed-cycle cooling water (3.2.1-36)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Gray cast iron piping, piping components, and piping elements exposed to soil (3.2.1-37)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Elastomers, elastomer seals, and components exposed to air-indoor, uncontrolled (external) (3.2.1-38)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces of Mechanical Components	Consistent with the GALL Report
Steel containment isolation piping and components (external surfaces) exposed to condensation (external) (3.2.1-39)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Steel ducting, piping, and components (external surfaces), ducting, closure bolting, containment isolation piping and components (external surfaces) exposed to air-indoor, uncontrolled (external) (3.2.1-40)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Steel external surfaces exposed to air-outdoor (external) (3.2.1-41)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Aluminum piping, piping components, and piping elements exposed to air-outdoor (3.2.1-42)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Elastomers, elastomer seals, and components exposed to air-indoor, uncontrolled (internal) (3.2.1-43)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	See SER Section 3.2.2.1.1
Steel piping and components (internal surfaces), ducting and components (internal surfaces) exposed to air-indoor, uncontrolled (internal) (3.2.1-44)	Loss of material caused by general corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	See SER Section 3.2.2.1.1
Steel encapsulation components exposed to air-indoor, uncontrolled (internal) (3.2.1-45)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Steel piping and components (internal surfaces) exposed to condensation (internal) (3.2.1-46)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel encapsulation components exposed to air with borated water leakage (Internal) (3.2.1-47)	Loss of material caused by general, pitting, crevice, and boric acid corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements (internal surfaces); tanks exposed to condensation (internal) (3.2.1-48)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-49)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy, stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.2.1-50)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel, copper alloy, stainless steel heat exchanger tubes exposed to lubricating oil (3.2.1-51)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete (3.2.1-52)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.2.1-53)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Steel; stainless steel underground piping, piping components, and piping elements exposed to air-indoor, uncontrolled or condensation (external) (3.2.1-53x)	Loss of material caused by general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.2.1-54)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	BWR Stress Corrosion Cracking, Water Chemistry, and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD	Consistent with the GALL Report (see SER Section 3.2.2.1.5)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to concrete (3.2.1-55)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557; and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Aluminum piping, piping components, and piping elements exposed to air-indoor, uncontrolled (internal/external) (3.2.1-56)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external), gas (3.2.1-57)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Copper-alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-58)	None	None	NA – No AEM or AMP	NA	Not applicable to BWRs (see SER Section 3.2.2.1.1)
Galvanized steel ducting, piping, and components exposed to air-indoor, controlled (external) (3.2.1-59)	None	None	NA – No AEM or AMP	NA	Not applicable to LGS

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass piping elements exposed to air-indoor, uncontrolled (external), lubricating oil, raw water, treated water, treated water (borated), air with borated water leakage, condensation (internal/external), gas, closed-cycle cooling water, air-outdoor (3.2.1-60)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Nickel alloy piping, piping components, and piping elements exposed to air-indoor, uncontrolled (External) (3.2.1-61)	None	None	NA – No AEM or AMP	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Nickel alloy piping, piping components, and piping elements exposed to air with borated water leakage (3.2.1-62)	None	None	NA – No AEM or AMP	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external), air with borated water leakage, concrete, gas, air-indoor, uncontrolled (internal) (3.2.1-63)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to air-indoor, controlled (external), gas (3.2.1-64)	None	None	NA – No AEM or AMP	NA	Not applicable to LGS (see SER Section 3.2.2.1.1)

The staff's review of the ESF systems component groups followed any one of several approaches. One approach, documented in SER Section 3.2.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.2.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.2.2.3, reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the ESF systems components is documented in SER Section 3.0.3.

3.2.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.2.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the ESF systems components:

- Bolting Integrity
- External Surfaces Monitoring of Mechanical Components
- Flow-Accelerated Corrosion
- Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components
- Lubricating Oil Analysis
- One-Time Inspection
- Selective Leaching
- TLAA
- Water Chemistry

LRA Tables 3.2.2-1 through 3.2.2-6 summarize AMRs for the ESF systems components and indicate AMRs claimed to be consistent with the GALL Report.
The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

LRA Table 3.2.1, item 3.2.1-15 addresses copper alloy, nickel alloy, steel, and stainless steel bolting and closure bolting exposed to any environment, including air-outdoor (external), raw water, treated borated water, fuel oil, treated water, and air-indoor, uncontrolled (external) which will be managed for loss of preload caused by thermal effects, gasket creep, and self-loosening. During its review of carbon steel, low-alloy steel, and stainless steel bolting exposed to treated water (external) and stainless steel bolting exposed to raw water (external) associated with item 3.2.1-15 for which the applicant cited generic note A, the staff noted that LRA Section B.2.1.11, Bolting Integrity states that, "Inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities." It is not clear to the staff how the submerged bolted connections will be inspected and how often inspections will occur. By letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-1 requesting the applicant to state the parameters that will be inspected for during opportunistic inspections of normally submerged bolting and the basis for why these parameters will be capable of assessing the condition of the bolting before loss of intended function occurs, and the minimum number of inspections that will be conducted during the period of extended operation.

In its response dated March 13, 2012, the applicant stated that the submerged bolts in the CS system, HPCI system, reactor core isolation cooling system, and RHR system are visually inspected for loss of material and loss of preload at least once every 10-year ISI inspection interval. The applicant also stated that the submerged bolts in the condenser and air removal system are visually inspected for loss of material and loss of preload whenever the expansion joint is replaced, which is planned on a 12-year frequency. The applicant further stated that the submerged bolts in the fuel pool cooling and cleanup system, and the circulating water system are visually inspected for loss of material and loss of preload when the fuel pool weir plates are adjusted and when the circulating water screens are removed, which normally occurs during refueling outages. The applicant stated that in each application, the bolting is not high strength. The visual inspection checks for degradation including corrosion and missing or loose parts.

The staff finds the applicant's response acceptable because the visual inspection techniques will be able to identify loss of material and loss of preload aging effects that enables assessment of the condition of the bolting before loss of intended function occurs; set inspection frequencies provide opportunities to inspect the components for aging; the applicant's program follows recommended industry bolting techniques including design, torqueing, gasket compression, and lubrication, which helps to maintain preload and the possibility of lubrication-related corrosion; the condenser and air removal system is continuously monitored for system pressure; and the applicant's CAP would provide additional opportunistic inspection opportunities for components. The staff's concern described in RAI 3.2.2.1.1-1 is resolved.

The staff concludes that for LRA item 3.2.1-15, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA AMR Tables 3.2.2-3 and 3.2.2-4 list gray cast iron turbine lube oil reservoirs exposed internally to lube oil; however, selective leaching is not considered to be an aging effect. The applicant proposes to manage aging of these components with the Lubricating Oil Analysis and One-Time Inspection programs.

According to the LRA, the Lubricating Oil Analysis program directs the condition monitoring activities (sampling, analyses, and trending) to manage loss of material and reduction of heat transfer in piping, piping components, piping elements, heat exchangers, and tanks. The One-Time Inspection program provides inspections focusing on locations that are isolated from the flow stream, that are stagnant, or have low flow for extended periods and are susceptible to the gradual accumulation or concentration of agents that promote certain aging effects. The inspections will include a representative sample of the system population and will focus on the bounding or lead components most susceptible to aging caused by time in service, and severity of operating conditions.

Selective leaching is known to occur in susceptible materials such as gray cast iron and uninhibited brasses with greater than 15-percent zinc when an electrolyte is present. Based on the information provided in the LRA, the staff was unable to determine whether susceptible locations will be included in the sample for inspection. Moreover, visual inspections alone may not be sufficient to detect selective leaching. Therefore, by letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-2, requesting the applicant to explain if the inspection samples will include susceptible locations to confirm that selective leaching does not occur in areas where water can accumulate. If it is determined that selective leaching is a relevant aging effect or mechanism to be managed, the applicant was requested to explain which program and inspection method(s) will be used to manage the loss of material caused by selective leaching. In its response, dated March 13, 2012, the applicant stated that Lubricating Oil Analysis program checks for water and particulates to detect evidence of contamination by moisture or excessive corrosion. It also cited element 6 of GALL Report AMP XI.M39 which states "phase-separated water in any amount is not acceptable."

The applicant concluded that the lack of water in the oil precludes the existence of an electrolyte in this environment, and the aging mechanism of selective leaching is not applicable. The applicant also stated that the HPCI and RCIC turbine lube oil reservoirs have not exhibited degradation caused by water pooling, and that both the HPCI and RCIC turbine lube oil reservoirs are sampled quarterly for water and are drained, cleaned, and inspected every 2 years. Lastly, the applicant stated that the efficacy of the Lube Oil Analysis program at minimizing the potential for water pooling is confirmed through the implementation of the One-Time Inspection program, which confirms the absence of corrosion in material subject to lube oil.

The staff finds the applicant's response acceptable because the Lubricating Oil Analysis program checks for the presence of water, and on a quarterly basis, it samples the turbine lube oil reservoirs for water, and every 2 years, the reservoirs are drained, cleaned, and inspected. These actions will timely detect and potentially prevent the accumulation of any water, which could lead to a loss of material. In addition, the effectiveness of the Lubricating Oil Analysis program is confirmed by the One-Time Inspection program. The staff's concern described in RAI 3.2.2.1.1-2 is resolved.

3.2.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.2.1 items 3.3.2.1-10, 3.3.2.1-28 through 3.2.1.34, 3.2.1.37, 3.2.1-39, 3.2.1-41, 3.2.1-42, 3.2.1-52, 3.2.1-53, 3.2.1-53x, 3.2.1.55, 3.2.1.59, 3.2.1-61, 3.2.1-62, and 3.2.1.64, the applicant claimed that they were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for these items.

For LRA Table 3.2.1 items 3.2.1-8, 3.2.1-9, 3.2.1-20, 3.2.1-21, 3.2.1-22, 3.2.1-24, 3.2.1.36, 3.2.1-45, 3.2.1-47, and 3.2.1-58, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to PWRs. The staff reviewed the SRP-LR, confirmed these items only apply to PWRs, and finds these items are not applicable to LGS.

LRA Table 3.2.1, item 3.2.1-12 addresses steel high-strength closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18 "Bolting Integrity" to manage cracking caused by cyclic loading and stress corrosion cracking for this component group. The applicant stated that this item is not applicable because there is no steel high-strength bolting exposed to air with steam or water leakage in the engineered safety feature systems. The staff evaluated the applicant's claim and finds it acceptable because:

- The UFSAR states that ASTM A-193 fasteners were used in the engineered safety features systems. The minimum tensile specification for A-193 fasteners is 120 ksi. RG 1.65, issued April 2010, states that a design conservative value of 150 ksi yield strength should be used to ensure that studs are relatively immune to stress corrosion cracking. Given that there is a 30 ksi margin between the minimum tensile specification and the threshold for SCC, it is reasonable to conclude that LGS Units 1 and 2 do not have any high-strength fasteners.

- LRA Section 4.3.2 states that for the ESF systems, the cyclic loading was based on stress range reduction factor methodology. The TLAA evaluation states that the 60-year cycle projections demonstrate that the total number of thermal and pressure cycles of all of the transient types added together will not exceed 7,000 cycles during the period of extended operation. Therefore, it is reasonable to conclude that cracking caused by cyclic loading does not need to be managed for aging.

LRA Table 3.2.1, item 3.2.1-14 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18 "Bolting Integrity" to manage loss of material caused by general corrosion for this component group. The applicant stated that this item is not applicable because there is no steel closure bolting exposed to air with steam or water leakage in the engineered safety features systems. The staff evaluated the applicant's claim and found it acceptable because all ESF system bolting exposed to air is being managed for loss of material by the Bolting Integrity program citing item 3.2.1-13, or the External Surfaces Monitoring of Mechanical Components program citing item 3.2.1-40. Both of these programs conduct periodic visual inspections capable of detecting loss of material caused by general corrosion in bolting, and use of these programs is consistent with the GALL Report.

LRA Table 3.2.1, item 3.2.1-18 addresses the internal surfaces of stainless steel containment isolation piping and components exposed to treated water. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry" and XI.M32, "One-Time Inspection" to manage loss of material caused by pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because there are no stainless steel containment isolation piping and components exposed to treated water in the ESF systems. The staff evaluated the applicant's claim and found it acceptable because, as stated in LRA Section 2.3.2.2, the containment isolation piping and components are evaluated in the RCPB systems and are not included in the ESF system. The staff confirmed that stainless steel piping exposed to treated water that are managed for loss of material in the RCPB systems reference LRA items 3.2.1-17 or 3.3.1-25, which manage these components in a manner consistent with LRA item 3.2.1-18 and the GALL Report recommendations.

LRA Table 3.2.1, items 3.2.1-26 and 3.2.1-27 address stainless steel heat exchanger tubes exposed to raw water that are being managed for reduction of heat transfer caused by fouling. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System" to manage reduction of heat transfer for this component group. The applicant stated that these items are not applicable because the reduction of heat transfer for stainless steel RHR heat exchanger components exposed to raw water is evaluated in auxiliary systems Table 3.3.1, item 3.3.1-42. The staff noted that LRA item 3.3.1-42 is similar to items 3.2.1-26 and 3.2.1-27 and also uses the Open-Cycle Cooling Water System program to manage this aging effect for comparable components. The staff evaluated the applicant's claim and found it acceptable because the staff confirmed that stainless steel RHR heat exchanger components exposed to raw water in the ESF systems are evaluated in the auxiliary systems section and reference LRA item 3.3.1-42, which manage for loss of material in a manner consistent with LRA items 3.2.1-26 and 3.2.1-27, and the GALL Report recommendations.

LRA Table 3.2.1, item 3.2.1-43 addresses elastomers, elastomer seals, and components exposed internally to uncontrolled indoor air. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" to manage hardening and loss of strength caused by elastomer degradation for this component group. The applicant stated that this item is not applicable because there are no elastomer seals and components exposed internally to uncontrolled indoor air in ESF systems. The staff evaluated the applicant's claim and found it acceptable because a review of LRA Section 2.3.2 and the LGS Units 1 and 2 UFSAR did not reveal any elastomeric materials exposed internally to uncontrolled indoor air, and LRA Table 3.2.2-6 lists elastomeric items associated with ducting and components and flexible connectors for which the internal environment is identified as internal wetted air or gas. These elastomeric items are being age managed by GALL Report AMP XI.M38, as recommended by the GALL Report.

LRA Table 3.2.1, item 3.2.1-44 addresses steel piping and components (internal surfaces), ducting and components (internal surfaces) exposed internally to uncontrolled indoor air. The GALL Report recommends GALL Report AMP XI. M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage loss of material caused by general corrosion. The LRA states that this item is not applicable because there are no steel piping and components, ducting and components with internal surfaces exposed to uncontrolled indoor air in the ESF systems. The LRA also states that internal environment is considered condensation by LRA Table 3.2.1, item 3.2.1-46, which credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program for managing steel piping and components for loss of material. The staff evaluated the applicant's claim and finds it acceptable because the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program proposes to manage loss of material using visual inspections that are capable of detecting aging before loss of intended function.

3.2.2.1.2 Loss of Material Caused by General, Pitting, and Crevice Corrosion

LRA Table 3.2.1, item 3.2.1-16 addresses steel containment piping and components (internal surfaces) and piping, piping components, and piping elements exposed to treated water that will be managed for loss of material caused by general, pitting, and crevice corrosion. The staff noted that the applicant also applied this item to heat exchangers, tanks, and bolting and for all of the subject components (except bolting) exposed to a steam environment. For the AMR items that cite generic note E, the LRA credits the Bolting Integrity program to manage the aging effect for carbon and low-alloy steel bolting. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection" to ensure that this aging effect is adequately managed for piping components.

GALL Report AMPs XI.M2 and XI.M32 recommend using water chemistry controls and a one-time inspection to verify the effectiveness of those controls to manage aging. The staff noted that, while LRA Section B.2.1.11, Bolting Integrity states that "inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities," it was not clear how the submerged bolted connections will be inspected and how often inspections will occur. By letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-1 requesting the applicant to state the parameters that will be inspected during opportunistic inspections of normally submerged bolting, the basis for why these parameters will be capable of assessing the condition of the bolting before loss of intended function occurs, and the minimum number of inspections that will be conducted during the period of extended operation. The applicant's response and the staff's evaluation of that response are documented in SER Section 3.2.2.1.

The staff's evaluation of the Bolting Integrity program is documented in SER Section 3.0.3.2.3. The staff noted that the applicant will visually inspect submerged bolting for loss of material at least once every 10-year ISI inspection interval in the CS, HPCI, and reactor core isolation cooling systems and at least once every 12 years in the condenser and air removal system. The staff also noted that water in the submerged environments in the above systems is maintained with the condensate cleanup system, which uses filters and demineralizers to maintain water purity. In its review of components associated with item 3.2.1-16 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Bolting Integrity program acceptable because the water quality in the submerged environments is maintained to minimize contaminants that could promote corrosion and the periodic visual inspections in the Bolting Integrity program are capable of detecting loss of material before loss of intended function.

3.2.2.1.3 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Table 3.2.1, item 3.2.1-17 addresses aluminum and stainless steel piping, piping components, and piping elements exposed to treated water that will be managed for loss of material caused by general, pitting, and crevice corrosion. The staff noted that the applicant only applied this item to stainless steel piping, piping component, and piping elements exposed to treated water and steam. For the AMR items that cite generic note E, the LRA credits the Bolting Integrity program to manage the aging effect for carbon and low-alloy steel bolting. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection" to ensure that these aging effects are adequately managed for piping components.

The applicant stated that for item 3.2.1-17, the applicability is limited to stainless steel piping, piping components, and piping elements exposed to treated water and steam. The staff noted that a search of the LGS Units 1 and 2 UFSAR confirmed that no aluminum piping, piping component, and piping elements exposed to treated water and steam are within the scope of license renewal and present in the ESF systems.

GALL Report AMPs XI.M2 and XI.M32 recommend using water chemistry controls and a one-time inspection to verify the effectiveness of those controls to manage aging. The staff noted that, while LRA Section B.2.1.11, Bolting Integrity states that "inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities," it is not clear how the submerged bolted connections will be inspected and how often inspections will occur. By letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-1 requesting the applicant to state the parameters that will be inspected during opportunistic inspections of normally submerged bolting, the basis for why these parameters will be capable of assessing the condition of the bolting before loss of intended function occurs, and the minimum number of inspections that will be conducted during the period of extended operation. The applicant's response and the staff's evaluation of that response are documented in SER Section 3.2.2.1.

The staff's evaluation of the Bolting Integrity program is documented in SER Section 3.0.3.2.3. The staff noted that the applicant will visually inspect submerged bolting for loss of material at least once every 10-year ISI inspection interval in the CS, HPCI, RCIC cooling, and RHR systems. The staff also noted that water in the submerged environments in the above systems is maintained with the condensate cleanup system, which uses filters and demineralizers to maintain water purity. In its review of components associated with item 3.2.1-17 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Bolting Integrity program acceptable because the water quality in the submerged environments is maintained to minimize contaminants that could promote corrosion and the periodic visual inspections in the Bolting Integrity program are capable of detecting loss of material before loss of intended function.

3.2.2.1.4 Loss of Material Caused by Pitting, Crevice, and Microbiologically-Influenced Corrosion; Fouling that Leads to Corrosion

LRA Table 3.2.1, item 3.2.1-25 addresses stainless steel heat exchanger and containment isolation piping components exposed to raw water that will be managed for loss of material caused by pitting, crevice, and microbiologically influenced corrosion (MIC) and fouling that leads to corrosion. For the AMR item that cites generic note E, the LRA credits the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program to manage the aging effects for stainless steel components, including removable screens, screen frames, weir plates, and splitter assembly vortex suppressors. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure these aging effects are adequately managed.

GALL Report AMP XI.M20 recommends using periodic visual inspections and water chemistry controls to manage aging. The staff noted that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program proposes to manage the aging of stainless steel components through the use of periodic visual inspection. The staff also noted that water chemistry controls associated with the Open-Cycle Cooling Water System program would equally affect the water control structures, so no additional chemistry controls would be needed.

The staff's evaluation of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.2.1-25 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is acceptable because the program performs comparable visual inspections to identify loss of material and corrosion as those that are performed in the Open-Cycle Cooling Water System program.

The staff concludes that for LRA item 3.2.1-25, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.5 Cracking Caused by Stress Corrosion Cracking

LRA Table 3.2.1, item 3.2.1-54 addresses stainless steel piping, piping components, and piping elements exposed to treated water greater than 60° C (140 °F), which will be managed for cracking caused by SCC and IGSCC. For this AMR item, the GALL Report recommends using GALL Report AMP XI.M2, "Water Chemistry," and GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking." GALL Report AMP XI.M2 includes water chemistry control to manage aging by limiting the concentrations of chemical species known to cause SCC and IGSCC and controlling dissolved oxygen levels to minimize the environmental effect on the aging effect. GALL Report AMP XI.M7 includes volumetric examinations of the welds of stainless steel and nickel alloy components to detect and manage cracking caused by SCC and IGSCC.

For the AMR item that addresses stainless steel valve bodies (LRA Table 3.1.2-1) with generic note E, the LRA credits the Water Chemistry program and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program to manage the aging effect of these components. The Water Chemistry program proposes to manage the aging of the components through periodic monitoring and control of the water chemistry to mitigate environmental effect on SCC and IGSCC. The ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes visual, surface, and volumetric examinations to manage aging in accordance with ASME Code, Section XI.

The staff's evaluations of the Water Chemistry and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.1, respectively. In its review of the stainless steel valve bodies associated with item 3.2.1-54, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry program and ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program acceptable because (1) the Water Chemistry program limits the concentrations of chemical species known to cause SCC and IGSCC and controls the dissolved oxygen level to minimize the environmental effect on aging, and (2) the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program includes visual, surface, and volumetric examinations in accordance with ASME Code Section XI, which are adequate to detect and manage the aging effect.

The staff concludes that for LRA item 3.2.1-54, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.1.6 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed were not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed were not applicable are not applicable to LGS Units 1 and 2.

As discussed in SER Section 3.0.2.2, for those AMRs that the applicant claimed consistency with the GALL Report, the staff evaluated the applicant's claim of consistency. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent.

Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.2.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.2.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the ESF systems components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- loss of material caused by cladding breach
- loss of material caused by pitting and crevice corrosion
- loss of material caused by erosion
- loss of material caused by general corrosion and fouling that leads to corrosion
- cracking caused by SCC
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.2.2.2.The staff's review of the applicant's further evaluation follows.

3.2.2.2.1 Cumulative Fatigue Damage

LRA Section 3.2.2.2.1 is associated with LRA Table 3.2.1 item 3.2.1-1 that addresses steel and stainless steel piping, piping components, and piping elements exposed to treated water in the ESF systems and are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3 and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that its evaluation of the TLAA is addressed separately in LRA Section 4.3.

The staff reviewed LRA Section 3.2.2.2.1 against the criteria in SRP-LR Section 3.2.2.2.1, which states that cumulative fatigue damage of steel and stainless steel piping, piping components, and piping elements in the ECCS is a TLAA, and that these TLAAs are to be evaluated in accordance with 10 CFR 54.21(c) and SRP-LR Section 4.3. The staff also reviewed the AMR items associated with LRA Section 3.2.2.2.1, and found that the AMR results are consistent with the GALL Report and SRP-LR.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.2.2.2.1 criteria. For those items that apply to LRA Section 3.2.2.2.1, the staff determined that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

3.2.2.2.2 Loss of Material Due to Cladding Breach

LRA Section 3.2.2.2.2, associated with LRA Table 3.2.1, item 3.2.1-2, addresses loss of material caused by cladding breach in PWR steel pump casings with stainless steel cladding exposed to treated borated water. The applicant stated that this item is not applicable because it is applicable to PWRs only. The staff confirmed that this item is associated only with PWR plants. Therefore, the staff finds the applicant's determination acceptable.

3.2.2.2.3 Loss of Material Due to Pitting and Crevice Corrosion

The staff reviewed LRA Section 3.2.2.2.3 against the following criteria in SRP-LR Section 3.2.2.2.3:

(1) LRA Section 3.2.2.2.3, item 1, associated with LRA Table 3.2.1, item 3.2.1-3, addresses loss of material caused by pitting and crevice corrosion in stainless steel partially-encased tanks with breached moisture barrier exposed to raw water. The applicant stated that this item is not applicable because the item is only applicable to PWR plants. The staff evaluated the applicant's claim and finds it acceptable because item 3.2.1-3 is only applicable to PWRs and does not apply to LGS.

(2) LRA Section 3.2.2.2.3, item 2, associated with LRA Table 3.2.1, item 3.2.1-4, addresses stainless steel piping, piping components, piping elements, and tanks exposed to air-outdoor. The applicant stated that this item is not applicable because there are no ESF system components exposed to an outdoor air environment. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and finds that no stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air are within the scope of license renewal and present in the ESF systems.

3.2.2.2.4 Loss of Material Caused by Erosion

LRA Section 3.2.2.2.4, associated with LRA Table 3.2.1, item 3.2.1-5, addresses loss of material caused by erosion in stainless steel minimum flow recirculation orifices exposed to treated borated water for PWR high-pressure safety injection (HPSI) pumps. The applicant stated that item 3.2.1-5 is not applicable because it only applies to PWRs. The staff evaluated the applicant's claim and finds it acceptable because item 3.2.1-5 is only applicable to PWRs and does not apply to LGS.

3.2.2.2.5 Loss of Material Caused by General Corrosion and Fouling that Leads to Corrosion

LRA Section 3.2.2.2.5, associated with LRA Table 3.2.1, item 3.2.1-6, addresses loss of material caused by general corrosion and fouling that leads to corrosion in steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air-indoor, uncontrolled. The applicant stated that this item is not applicable because there are no steel spray system flow orifices or nozzles in an uncontrolled indoor air environment in the ESF systems. The applicant also stated that the drywell and suppression chamber spray nozzles are brass. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and finds that no steel drywell and suppression chamber spray system nozzle and flow orifice internal surfaces exposed to air-indoor, uncontrolled are within the scope of license renewal and present in the ESF systems.

3.2.2.2.6 Cracking Caused by Stress Corrosion Cracking

LRA Section 3.2.2.2.6, associated with LRA Table 3.2.1, item 3.2.1-7, addresses stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. The applicant stated that this item is not applicable because there are no components in the ESF systems exposed to an outdoor air environment. The staff reviewed LRA Sections 2.3.2 and 3.2 and the UFSAR and finds that no stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air are within the scope of license renewal and present in the ESF systems.

3.2.2.2.7 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.2.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.2.2-1 through 3.2.2-6, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.2.2-1 through 3.2.2-6, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether 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. The staff's evaluation is documented in the following sections.

3.2.2.3.1 Containment Atmosphere Control - Summary of Aging Management Review – LRA Table 3.2.2-1

The staff reviewed LRA Table 3.2.2-1, which summarizes the results of AMR evaluations for the containment atmosphere control system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.2.2.3.2 Core Spray - Summary of Aging Management Review – LRA Table 3.2.2-2

The staff reviewed LRA Table 3.2.2-2, which summarizes the results of AMR evaluations for the CS component groups.

In LRA Table 3.2.2-2, the applicant stated that for polymeric piping, piping components, and piping elements exposed externally to uncontrolled indoor air and internally to lubricating oil there is no aging effect and no AMP is proposed. The AMR items cite generic note F. These items cite plant-specific note 4, which states that the component is butyrate plastic and this material has no aging effects when exposed externally to indoor air and internally to lubricating oil.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable based on its review of Chemical Resistance of Plastics and

Elastomers (4th Electronic Edition) by the Plastics Design Library Staff, Plastics Design Library (PDL), which states that the appearance of the material was unchanged when exposed to environments such as lubricating oil, machining oils, transformer oils, water, etc. The staff noted that this document assigns a PDL rating that is a weighted value scale of test results when materials are exposed to specific environments. For a description of the PDL rating, see Fluorinated Coatings and Finishes Handbook – The Definitive Users Guide, Laurence McKeen, 2006, Plastics Design Laboratory, Section 1.2. The scale ranges from 0, worst, to 9, best. The PDL rating for butyrate plastic ranged from 7-9. In addition, exposure to accelerated outdoor and accelerated weather resulted in an average PDL specimen rating of 5 for a range of exposures from one-half a year to 3 years. The indoor air environment will be less severe. A PDL rating of 5 yields some stress cracking, but the material remains pliable. Website vendor information, Tentite Plastics –Weathering of Tentite Butyrate, Eastman Publication PP104B, May 1999, http://www.eastman.com, states that butyrate compounds are resistant to the indoor air environment even when not augmented with heavy pigmentation to mitigate the impact of direct sunlight.

In LRA Tables 3.2.2-2 and 3.3.2-14, the applicant stated that for zinc piping, piping components, and piping elements and valve bodies exposed to uncontrolled indoor air, there is no aging effect and no AMP is proposed. The AMR items cite generic note F. The items associated with zinc piping and valve bodies cite plant-specific note 5 (LRA Table 3.2.2-2) and note 2 (Table 3.3.2-14), respectively, which state that the component is zinc die cast and has no aging effects in an indoor air environment.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff noted that LRA Table 3.0-2 states that humidity levels up to 100 percent are assumed in the uncontrolled indoor air environment and components may be wet. The staff also noted that the GALL Report item III.B2.TP-6 states that zinc-coated steel should be managed for loss of material when exposed to potentially wet air environments. By letter dated January 17, 2012, the staff issued RAI 3.0.2-1 requesting the applicant to identify which AMR items in the LRA are exposed to an uncontrolled indoor air environment for which humidity, condensation, moisture, or contaminants are present and, for those exposed to potentially aggressive environments, determine the aging effects and select an appropriate AMP. The applicant's response and the staff's evaluation of that response are documented in SER Section 3.0.1.2. In the response, the applicant stated that the environment of uncontrolled indoor air does not contain humidity, condensation, moisture, or contaminants.

The staff finds the applicant's AMR acceptable based on its review of the Metals Handbook, Desk Edition, 2nd Edition, which states zinc has a high degree of atmospheric corrosion resistance caused by the formation of carbonate films. Also, the GALL Report item VII.J.AP-13 states that galvanized (zinc-coated) steel has no aging effect in an uncontrolled indoor air environment.

In LRA Table 3.2.2-2, the applicant stated that zinc piping, piping components, and piping elements exposed to lubricating oil will be managed for loss of material by the Lubricating Oil Analysis and One-Time Inspection programs. The AMR items cites generic note F, 5. Items associated with this material in Table 3.2.2-2 cite plant-specific note 5, which states that although NUREG-1801 does not provide a line for zinc piping components, they are susceptible to loss of material and are inspected per the Lubricating Oil Analysis program.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the GALL Report does not address zinc piping, piping components, and piping elements exposed to lubricating oil and loss of material as the aging effect. However, the staff noted that the GALL Report does address copper-alloy components with 15 percent zinc or more exposed to lubricating oil and loss of material as the aging effect. Based on its review of the GALL Report and the ASM Handbook, both of which state that loss of material in the form of pitting and crevice corrosion may occur in this environment, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Lubricating Oil Analysis and One-Time Inspection programs is documented in SER Sections 3.0.3.1.17 and 3.0.3.1.14. The staff finds the applicant's proposal to manage aging using the Lubricating Oil Analysis and One-Time Inspection programs acceptable because the Lubricating Oil Analysis program will be able to detect and minimize contaminants in lubricating oil; and the staff confirmed that the One-Time Inspection program will be used to examine selected components at susceptible locations where contaminants such as water could accumulate, which is consistent with the GALL Report.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

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

The staff reviewed LRA Table 3.2.2-3, which summarizes the results of AMR evaluations for the HPCI system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

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

The staff reviewed LRA Table 3.2.2-4, which summarizes the results of AMR evaluations for the reactor core isolation cooling system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.2.2.3.5 Residual Heat Removal - Summary of Aging Management Review – LRA Table 3.2.2-5

The staff reviewed LRA Table 3.2.2-1, which summarizes the results of AMR evaluations for the RHR system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.2.2.3.6 Standby Gas Treatment – Summary of Aging Management Review – LRA Table 3.2.2-6

The staff reviewed LRA Table 3.2.2-6, which summarizes the results of AMR evaluations for the Standby Gas Treatment component groups.

In LRA Table 3.2.2-6, the applicant stated that elastomer ducting and components, flexible connections exposed to air/gas – wetted (internal) will be managed for loss of material, hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the LRA Table 3.0-1 states that air/gas environments contain significant amounts of moisture where condensation or water pooling may occur. Based on its review of the GALL Report, which states that elastomers exposed to a water environment (e.g., raw water, treated water, and closed cycle cooling water) are subject to loss of material and hardening and loss of strength, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program's use of periodic opportunistic inspections during component surveillance, system inspections, and maintenance activities are effective measures for identifying and managing these aging effects.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.2.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the ESF system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3 Aging Management of Auxiliary Systems

This SER section documents the staff's review of the applicant's AMR results for the auxiliary systems components and component groups of:

- auxiliary steam
- closed cooling water
- compressed air
- control enclosure ventilation

- CRD
- cranes and hoists
- EDG enclosure ventilation
- EDG
- fire protection
- fuel handling and storage
- fuel pool cooling and cleanup
- nonsafety-related service water
- plant drainage
- primary containment instrument gas
- primary containment leak testing
- primary containment ventilation
- process radiation monitoring
- process and post-accident sampling
- radwaste
- reactor enclosure ventilation
- reactor water cleanup
- safety-related service water
- spray pond pump house ventilation
- SLC
- traversing in-core probe
- water treatment and distribution

3.3.1 Summary of Technical Information in the Application

LRA Section 3.3 provides AMR results for the auxiliary systems components and component groups. LRA Table 3.3.1, "Summary of Aging Management Programs for Auxiliary Systems Evaluated in Chapter VII of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the auxiliary systems components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.3.2 Staff Evaluation

The staff reviewed LRA Section 3.3 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components within the scope of license renewal and subject to an AMR, 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 conducted review of AMRs to ensure the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.3.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.3.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.3.2.3.

For SSCs that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to verify the applicant's claims.

Table 3.3-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.3 and addressed in the GALL Report.

Table 3.3-1 Staff Evaluation for Auxiliary Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel cranes: structural girders exposed to air-indoor, uncontrolled (external) (3.3.1-1)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation for structural girders of cranes that fall within the scope of 10 CFR Part 54 (Standard Review Plan, Section 4.7, "Other Plant-Specific Time-Limited Aging Analyses," for generic guidance for meeting the requirements of 10 CFR 54.21(c)(1))	Yes	TLAA	Consistent with the GALL Report (see Section 3.3.2.2.1)
Stainless steel, steel heat exchanger components and tubes, piping, piping components, and piping elements exposed to treated borated water, air-indoor, uncontrolled, treated water (3.3.1-2)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation. See the SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.3.2.2.1)
Stainless steel heat exchanger components, non-regenerative exposed to treated borated water >60 °C (>140 °F) (3.3.1-3)	Cracking caused by stress corrosion cracking; cyclic loading	Chapter XI.M2, "Water Chemistry" The AMP is to be augmented by verifying the absence of cracking caused by stress corrosion cracking and cyclic loading. An acceptable verification program is to include temperature and radioactivity monitoring of the shell side water, and eddy current testing of tubes.	No	NA	Not applicable to BWRs (see SER Section 3.3.2.2.2)
Stainless steel Piping, piping components, and piping elements; tanks exposed to Air-outdoor (3.3.1-4)	Cracking caused by stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with GALL Report (see Section 3.3.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with stainless steel or nickel-alloy cladding) pump casings exposed to treated borated water (3.3.1-5)	Loss of material caused by cladding breach	A plant-specific aging management program is to be evaluated. Reference NRC Information Notice 94-63, "Boric Acid Corrosion of Charging Pump Casings Caused by Cladding Cracks."	No	NA	Not applicable to BWRs (see SER Section 3.3.2.2.4)
Stainless steel Piping, piping components, and piping elements; tanks exposed to air-outdoor (3.3.1-6)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components and Buried and Underground Piping and Tanks	Consistent with the GALL Report (see Section 3.3.2.2.5)
Stainless steel high-pressure pump, casing exposed to treated borated water (3.3.1-7)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	NA	Not applicable to BWRs (see SER Section 3.3.2.1.1)
Stainless steel heat exchanger components and tubes exposed to treated borated water >60 °C (>140 °F) (3.3.1-8)	Cracking caused by cyclic loading	Chapter XI.M1, "ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD"	No	NA	Not applicable to BWRs (see SER Section 3.3.2.1.1)
Steel, aluminum, copper alloy (>15% Zn or >8% Al) external surfaces, piping, piping components, and piping elements, bolting exposed to air with borated water leakage (3.3.1-9)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	NA	Not applicable to BWRs (see SER Section 3.3.2.1.1)
Steel, high-strength closure bolting exposed to air with steam or water leakage (3.3.1-10)	Cracking caused by stress corrosion cracking; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Steel, high-strength high-pressure pump, closure bolting exposed to air with steam or water leakage (3.3.1-11)	Cracking caused by stress corrosion cracking; cyclic loading	Chapter XI.M18, "Bolting Integrity"	No	NA	Not applicable to BWRs (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel closure bolting, bolting exposed to condensation, air-indoor, uncontrolled (external), air-outdoor (external) (3.3.1-12)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity and Buried and Underground Piping and Tanks	Consistent with the GALL Report (see SER Section 3.3.2.1.2)
Steel closure bolting exposed to air with steam or water leakage (3.3.1-13)	Loss of material caused by general corrosion	Chapter XI.M18, "Bolting Integrity"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Steel, stainless steel bolting exposed to soil (3.3.1-14)	Loss of preload	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Steel; stainless steel, copper alloy, nickel alloy, stainless steel closure bolting, bolting exposed to air-indoor, uncontrolled (external), any environment, air-outdoor (external), raw water, treated borated water, fuel oil, treated water (3.3.1-15)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report (see SER Section 3.3.2.1)
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.3.1-16)	Cracking caused by stress corrosion cracking, intergranular stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M25, "BWR Reactor Water Cleanup System"	No	Water Chemistry and BWR Reactor Water Cleanup System	Consistent with the GALL Report
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-17)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Stainless steel high-pressure pump, casing, piping, piping components, and piping elements exposed to treated borated water >60 °C (>140 °F), sodium pentaborate solution >60 °C (>140 °F) (3.3.1-18)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel regenerative heat exchanger components exposed to treated water >60 °C (>140 °F) (3.3.1-19)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel, stainless steel; steel with stainless steel cladding heat exchanger components exposed to treated borated water >60 °C (>140 °F), treated water >60 °C (>140 °F) (3.3.1-20)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to treated water (3.3.1-21)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to treated water (3.3.1-22)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-23)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Aluminum piping, piping components, and piping elements exposed to treated water (3.3.1-24)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Stainless steel, stainless steel; steel with stainless steel cladding, aluminum piping, piping components, and piping elements, heat exchanger components exposed to treated water, sodium pentaborate solution (3.3.1-25)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry, One-Time Inspection, Bolting Integrity, and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.3.2.1.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with elastomer lining), steel (with elastomer lining or stainless steel cladding) piping, piping components, and piping elements exposed to treated water (3.3.1-26)	Loss of material caused by pitting and crevice corrosion (only for steel after lining/cladding degradation)	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Stainless steel heat exchanger tubes exposed to treated water (3.3.1-27)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Stainless steel, steel (with stainless steel or nickel alloy cladding) spent fuel storage racks (BWR), spent fuel storage racks (PWR), piping, piping components, and piping elements, piping, piping components, and piping elements; tanks exposed treated water >60 °C (>140 °F), treated borated water >60 °C (>140 °F) (3.3.1-28)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Steel (with stainless steel cladding); stainless steel piping, piping components, and piping elements exposed to treated borated water (3.3.1-29)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-30)	Changes in material properties caused by aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Fiberglass, HDPE Piping, piping components, and piping elements exposed to Raw water (internal) 3.3.1-30x)	Cracking, blistering, change in color caused by water absorption	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Not applicable	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-31)	Cracking caused by settling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to raw water (3.3.1-32)	Cracking caused by aggressive chemical attack and leaching; changes in material properties caused by aggressive chemical attack	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Elastomer seals and components exposed to raw water (3.3.1-32x)	Hardening and loss of strength caused by elastomer degradation; loss of material caused by erosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to raw water (3.3.1-33)	Loss of material caused by abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Fire Water System	Consistent with SRP-LR (see SER Section 3.3.2.1.4)
Nickel alloy, copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-34)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-35)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper-alloy piping, piping components, and piping elements exposed to raw water (3.3.1-36)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Steel (with coating or lining) piping, piping components, and piping elements exposed to raw water (3.3.1-37)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion; lining/coating degradation	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Copper alloy, steel heat exchanger components exposed to raw water (3.3.1-38)	Loss of material caused by general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-39)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-40)	Loss of material caused by pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-41)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Structures Monitoring Program and RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"	Consistent with SRP-LR (see SER Section 3.3.2.1.5)
Copper alloy, titanium, stainless steel heat exchanger tubes exposed to raw water (3.3.1-42)	Reduction of heat transfer caused by fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-43)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water >60 °C (>140 °F) (3.3.1-44)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Steel piping, piping components, and piping elements; tanks exposed to closed-cycle cooling water (3.3.1-45)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report
Steel, copper alloy heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-46)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report
Stainless steel; steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water (3.3.1-47)	Loss of material caused by microbiologically -influenced corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Aluminum piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-48)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water (3.3.1-49)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water Systems	Consistent with the GALL Report
Stainless steel, copper alloy, steel heat exchanger tubes exposed to closed-cycle cooling water (3.3.1-50)	Reduction of heat transfer caused by fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	Closed Treated Water System	Consistent with the GALL Report
Boraflex spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water (3.3.1-51)	Reduction of neutron-absorbing capacity caused by Boraflex degradation	Chapter XI.M22, "Boraflex Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Steel cranes: rails and structural girders exposed to air-indoor, uncontrolled (external) (3.3.1-52)	Loss of material caused by general corrosion	Chapter XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report
Steel cranes – rails exposed to air-indoor, uncontrolled (external) (3.3.1-53)	Loss of material caused by wear	Chapter XI.M23, "Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems"	No	Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to condensation (3.3.1-54)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M24, "Compressed Air Monitoring"	No	Compressed Air Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements: compressed air system exposed to condensation (internal) (3.3.1-55)	Loss of material caused by general and pitting corrosion	Chapter XI.M24, "Compressed Air Monitoring"	No	Compressed Air Monitoring	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-56)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M24, "Compressed Air Monitoring"	No	Compressed Air Monitoring and Open-Cycle Cooling Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.6)
Elastomers fire barrier penetration seals exposed to air-indoor, uncontrolled, air-outdoor (3.3.1-57)	Increased hardness; shrinkage; loss of strength caused by weathering	Chapter XI.M26, "Fire Protection"	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.7)
Steel halon/carbon dioxide fire suppression system piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external) (3.3.1-58)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M26, "Fire Protection"	No	Fire Protection	Consistent with the GALL Report
Steel fire rated doors exposed to air-indoor, uncontrolled, air-outdoor (3.3.1-59)	Loss of material caused by wear	Chapter XI.M26, "Fire Protection"	No	Fire Protection	Consistent with the GALL Report
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air-indoor, uncontrolled (3.3.1-60)	Concrete cracking and spalling caused by aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring"	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air-outdoor (3.3.1-61)	Cracking, loss of material caused by freeze-thaw, aggressive chemical attack, and reaction with aggregates	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring"	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete structural fire barriers: walls, ceilings and floors exposed to air-indoor, uncontrolled, air-outdoor (3.3.1-62)	Loss of material caused by corrosion of embedded steel	Chapter XI.M26, "Fire Protection," and Chapter XI.S6, "Structures Monitoring"	No	Fire Protection and Structures Monitoring	Consistent with the GALL Report
Steel fire hydrants exposed to air-outdoor (3.3.1-63)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M27, "Fire Water System"	No	Fire Water System	Consistent with the GALL Report
Steel, copper alloy piping, piping components, and piping elements exposed to raw water (3.3.1-64)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Fire Water System, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, RG 1.127 Inspection of Water-Control Structures Associated with Nuclear Power Plants, and Structures Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.8)
Aluminum piping, piping components, and piping elements exposed to raw water (3.3.1-65)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M27, "Fire Water System"	No	Fire Water System	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to raw water (3.3.1-66)	Loss of material caused by pitting and crevice corrosion; fouling that leads to corrosion	Chapter XI.M27, "Fire Water System"	No	Fire Water System	Consistent with the GALL Report
Steel tanks exposed to air-outdoor (external) (3.3.1-67)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks and Buried and Underground Piping and Tanks	Consistent with the GALL Report (see SER Section 3.3.2.1.9)
Steel piping, piping components, and piping elements exposed to fuel oil (3.3.1-68)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M30, "Fuel Oil Chemistry", and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper-alloy piping, piping components, and piping elements exposed to fuel oil (3.3.1-69)	Loss of material caused by general, pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Fuel Oil Chemistry, One-Time Inspection, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.10)
Steel piping, piping components, and piping elements; tanks exposed to fuel oil (3.3.1-70)	Loss of material caused by general, pitting, crevice, and microbiologically-influenced corrosion; fouling that leads to corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Fuel Oil Chemistry, One-Time Inspection, and Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.11)
Stainless steel, aluminum piping, piping components, and piping elements exposed to fuel oil (3.3.1-71)	Loss of material caused by pitting, crevice, and microbiologically-influenced corrosion	Chapter XI.M30, "Fuel Oil Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Fuel Oil Chemistry and One-Time Inspection	Consistent with the GALL Report
Gray cast iron, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements, heat exchanger components exposed to treated water, closed-cycle cooling water, soil, raw water (3.3.1-72)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	Selective Leaching	Consistent with the GALL Report
Concrete; cementitious material piping, piping components, and piping elements exposed to air-outdoor (3.3.1-73)	Changes in material properties caused by aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Concrete; cementitious material piping, piping components, and piping elements exposed to air-outdoor (3.3.1-74)	Cracking caused by settling	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to air-outdoor (3.3.1-75)	Cracking caused by aggressive chemical attack and leaching; Changes in material properties caused by aggressive chemical attack	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Elastomers, elastomer seals, and components exposed to air-indoor, uncontrolled (internal/external) (3.3.1-76)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (see SER Section 3.3.2.1.12)
Concrete; cementitious material piping, piping components, and piping elements exposed to air-outdoor (3.3.1-77)	Loss of material caused by abrasion, cavitation, aggressive chemical attack, and leaching	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Steel piping and components (external surfaces), ducting and components (external surfaces), ducting; closure bolting exposed to air-indoor, uncontrolled (external), air-indoor, uncontrolled (external), air-outdoor (external), condensation (external) (3.3.1-78)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring and Fire Protection	Consistent with the GALL Report (see SER Section 3.3.2.1.13)
Copper-alloy piping, piping components, and piping elements exposed to condensation (external) (3.3.1-79)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel heat exchanger components, piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external), air-outdoor (external) (3.3.1-80)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components, Buried Underground Piping and Tanks, and Fire Protections	Consistent with the GALL Report (see SER Section 3.3.2.1.13 and 3.3.2.1.14)
Copper alloy, aluminum piping, piping components, and piping elements exposed to air-outdoor (external), air-outdoor (3.3.1-81)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Elastomers, elastomer seals, and components exposed to air-indoor, uncontrolled (external) (3.3.1-82)	Loss of material caused by wear	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Stainless steel diesel engine exhaust piping, piping components, and piping elements exposed to diesel exhaust (3.3.1-83)	Cracking caused by stress corrosion cracking	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Elastomers, elastomer seals, and components exposed to closed-cycle cooling water (3.3.1-85)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Elastomers, linings, elastomer seals, and components exposed to treated borated water, treated water, raw water (3.3.1-86)	Hardening and loss of strength caused by elastomer degradation	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report (see SER Section 3.3.2.1.15)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel; stainless steel piping, piping components, and piping elements, piping, piping components, and piping elements, diesel engine exhaust exposed to raw water (potable), diesel exhaust (3.3.1-88)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel, copper-alloy piping, piping components, and piping elements exposed to moist air or condensation (internal) (3.3.1-89)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and Open-Cycle Cooling Water System	Consistent with the GALL Report (see SER Section 3.3.2.1.16)
Steel ducting and components (internal surfaces) exposed to condensation (internal) (3.3.1-90)	Loss of material caused by general, pitting, crevice, and (for drip pans and drain lines) microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel piping, piping components, and piping elements; tanks exposed to waste water (3.3.1-91)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to condensation (internal) (3.3.1-92)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and Compressed Air Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.17)
Copper-alloy Piping, piping components, and piping elements exposed to Raw water (potable) (3.3.1-93)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel ducting and components exposed to condensation (3.3.1-94)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Copper alloy, stainless steel, nickel alloy, steel piping, piping components, and piping elements, heat exchanger components, piping, piping components, and piping elements; tanks exposed to waste water, condensation (internal) (3.3.1-95)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Elastomers, elastomer seals, and components exposed to air-indoor, uncontrolled (internal) (3.3.1-96)	Loss of material caused by wear	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Steel piping, piping components, and piping elements, reactor coolant pump oil collection system: tanks, reactor coolant pump oil collection system: piping, tubing, valve bodies exposed to lubricating oil (3.3.1-97)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel heat exchanger components exposed to lubricating oil (3.3.1-98)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Copper alloy, aluminum piping, piping components, and piping elements exposed to lubricating oil (3.3.1-99)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements exposed to lubricating oil (3.3.1-100)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Aluminum heat exchanger tubes exposed to lubricating oil (3.3.1-101)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Boral®; boron steel, and other materials (excluding Boraflex) spent fuel storage racks: neutron-absorbing sheets (PWR), spent fuel storage racks: neutron-absorbing sheets (BWR) exposed to treated borated water, treated water (3.3.1-102)	Reduction of neutron-absorbi ng capacity; change in dimensions and loss of material caused by effects of SFP environment	Chapter XI.M40, "Monitoring of Neutron-Absorbing Materials other than Boraflex"	No	Monitoring of Neutron-Absorbin g Materials Other Than Boraflex	Consistent with the GALL Report
Reinforced concrete, asbestos cement piping, piping components, and piping elements exposed to soil or concrete (3.3.1-103)	Cracking caused by aggressive chemical attack and leaching; Changes in material properties caused by aggressive chemical attack	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
HDPE, fiberglass piping, piping components, and piping elements exposed to soil or concrete (3.3.1-104)	Cracking, blistering, change in color caused by water absorption	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)
Concrete cylinder piping, asbestos cement pipe piping, piping components, and piping elements exposed to soil or concrete (3.3.1-105)	Cracking, spalling, corrosion of rebar caused by exposure of rebar	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete (3.3.1-106)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks and Structures Monitoring	Consistent with the GALL Report (see SER Section 3.3.2.1.18)
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.3.1-107)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Titanium, super austenitic, aluminum, copper alloy, stainless steel piping, piping components, and piping elements, bolting exposed to soil or concrete (3.3.1-108)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (See SER Section 3.3.2.1.1)
Steel bolting exposed to soil or concrete (3.3.1-109)	Loss of material caused by general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried and Underground Piping and Tanks	Consistent with the GALL Report
Underground aluminum, copper alloy, stainless steel and steel piping, piping components, and piping elements (3.3.1-109x)	Loss of material caused by general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	See SER Section 3.3.2.1.1
Stainless steel piping, piping components, and piping elements exposed to treated water >60 °C (>140 °F) (3.3.1-110)	Cracking caused by stress corrosion cracking	Chapter XI.M7, "BWR Stress Corrosion Cracking," and Chapter XI.M2, "Water Chemistry"	No	NA	See SER Section 3.3.2.1.1
Steel structural steel exposed to air-indoor, uncontrolled (external) (3.3.1-111)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.3.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to concrete (3.3.1-112)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557; and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	NA	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to air-dry (internal/external), air-indoor, uncontrolled (internal/external), air-indoor, controlled (external), gas (3.3.1-113)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Copper-alloy piping, piping components, and piping elements exposed to air-indoor, uncontrolled (internal/external), air-dry, gas (3.3.1-114)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Copper-alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.3.1-115)	None	None	NA – No AEM or AMP	NA	Not applicable to BWRs (see SER Section 3.3.2.1.1)
Galvanized steel piping, piping components, and piping elements exposed to air-indoor, uncontrolled (3.3.1-116)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Glass piping elements exposed to air-indoor, uncontrolled (external), lubricating oil, closed-cycle cooling water, air-outdoor, fuel oil, raw water, treated water, treated borated water, air with borated water leakage, condensation (internal/external) gas (3.3.1-117)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Nickel alloy piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external) (3.3.1-118)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Nickel alloy, PVC, glass piping, piping components, and piping elements exposed to air with borated water leakage, air-indoor, uncontrolled, condensation (internal), waste water (3.3.1-119)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements exposed to air-indoor, uncontrolled (internal/external), air-indoor, uncontrolled (external), air with borated water leakage, concrete, air-dry, gas (3.3.1-120)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to air-indoor, controlled (external), air-dry, gas (3.3.1-121)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Titanium heat exchanger components, piping, piping components, and piping elements exposed to air-indoor, uncontrolled or air-outdoor (3.3.1-122)	None	None	NA – No AEM or AMP	Not applicable	Not applicable to LGS (see SER Section 3.3.2.1.1)
Titanium (ASTM grades 1,2, 7, 11, or 12 that contains >5% aluminum or more than 0.20% oxygen or any amount of tin) heat exchanger components other than tubes, piping, piping components, and piping elements exposed to raw water (3.3.1-123)	None	None	NA – No AEM or AMP	Not applicable	Not applicable to LGS (see SER Section 3.3.2.1.1)

The staff's review of the auxiliary systems component groups followed any one of several approaches. One approach, documented in SER Section 3.3.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.3.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.3.2.3, reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the auxiliary systems components is documented in SER Section 3.0.3.

3.3.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.3.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the auxiliary systems components:

- aboveground metallic tanks
- bolting integrity
- buried and underground piping and tanks
- BWR reactor water cleanup system

- closed treated water systems
- compressed air monitoring
- external surfaces monitoring of mechanical components
- fire protection
- fire water systems
- flow-accelerated corrosion
- fuel oil chemistry
- inspection of internal surfaces in miscellaneous piping and ducting components
- inspection of overhead heavy load and light load (related to refueling) handling systems
- lubricating oil analysis
- monitoring of neutron-absorbing materials other than Boraflex
- one-time inspection
- open-cycle cooling water system
- selective leaching
- structures monitoring
- TLAA
- water chemistry

LRA Tables 3.3.2-1 through 3.3.2-26 summarize AMRs for the auxiliary system components and indicate AMRs claimed to be consistent with the GALL Report.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

LRA Table 3.3.1, item 3.3.1-15 addresses steel, stainless steel, copper alloy, and nickel alloy closure bolting exposed to air-indoor, uncontrolled (external), any environment including, air-outdoor (external), raw water, treated borated water, fuel oil, and treated water. During its review of stainless steel bolting exposed to treated water (external) associated with item 3.3.1-15 for which the applicant cited generic note A, the staff noted that while LRA Section B.2.1.11, Bolting Integrity states that, "Inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities," it is not clear to the staff how the submerged bolted connections will be inspected and how often inspections will occur. By letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-1 requesting the applicant to state the parameters that will be inspected for during opportunistic inspections of normally submerged bolting and the basis for why these parameters will be capable of assessing the condition of the bolting before loss of intended function occurs, and the minimum number of inspections that will be conducted during the period of extended operation.

In its response dated March 13, 2012, the applicant stated that the submerged bolts in the CS system, HPCI system, RCIC system, and RHR system are visually inspected for loss of material and loss of preload at least once every 10-year ISI inspection interval. The applicant also stated that the submerged bolts in the condenser and air removal system are visually inspected for loss of material and loss of preload at least once every 12-year replacement interval. The applicant further stated that the submerged bolts in the fuel pool cooling and cleanup system, and the circulating water system are visually inspected for loss of material and loss of preload every refueling outage during planned maintenance. The applicant stated that in each application, the bolting is not high strength. The visual inspection checks for degradation including corrosion and missing or loose parts.

The staff finds the applicant's response acceptable because the visual inspection techniques will be able to identify loss of material and loss of preload aging effects that enables assessment of the condition of the bolting before loss of intended function occurs, set inspection frequencies, and provide opportunities to inspect the components for aging. The applicant's program follows recommended industry bolting techniques including design, torquing, gasket compression, and lubrication that help to maintain preload and the possibility of lubrication-related corrosion. The condenser and air removal system is continuously monitored for system pressure, and the applicant's CAP will provide additional opportunistic inspection opportunities for components. The staff's concern described in RAI 3.2.2.1.1-1 is resolved.

The staff concludes that for LRA item 3.3.1-15, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).
In the LRA AMR tables, there are several entries for copper alloy with 15-percent zinc or more or gray cast iron components internally exposed to "air/gas – wetted," which will be managed for loss of material by the Inspection of Internal Surfaces of Miscellaneous Piping and Ducting program. According to the LRA, this program uses periodic and opportunistic inspections of the internal surfaces of components augmented by physical manipulation of flexible elastomers where appropriate.

The LRA defines "air/gas – wetted" as "air/gas environments containing significant amounts of moisture where condensation or water pooling may occur. This environment includes air with enough moisture to facilitate loss of material in steel caused by general, pitting, and crevice corrosion."

Since selective leaching is known to occur in susceptible materials such as gray cast iron and uninhibited brasses with greater than 15-percent zinc when moisture or water an electrolyte is present, the staff was concerned that visual inspections alone may not be sufficient to detect selective leaching. Therefore, by letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-3 requesting the applicant to explain why copper alloy with 15-percent zinc or more or gray cast iron components internally exposed to air/gas – wetted are not being managed for selective leaching. If it is determined that selective leaching is an appropriate aging effect or mechanism to be managed, the applicant was requested to explain which AMP and inspection method(s) will be used to manage the loss of material caused by selective leaching.

In its response dated March 13, 2012, as corrected by letter dated March 30, 2012, the applicant provided a listing of the copper alloy with 15-percent zinc or more and gray cast iron components exposed to an internal environment of air/gas – wetted. These included components and fittings in the control enclosure ventilation, SGTS, RHR, EDG, fire protection, PCIG, and HPCI systems. The applicant stated that it performed an evaluation of the design and operating conditions of each component to assess the potential for significant moisture to accumulate and water pooling to occur.

The applicant found that in two instances–the EDG system dirty fuel oil drain tank level glass valves and the PCIG receiver drain traps–the components accumulate condensation and are

exposed to significant moisture. The applicant stated that it revised LRA Table 3.3.2-8 to include loss of material caused by selective leaching for the EDG dirty fuel oil drain tank level glass valves, and LRA Table 3.3.2-14 and LRA Section 3.3.2.1.14 to include loss of material caused by selective leaching for the PCIG receiver drain traps. For the remaining components and fittings made of copper alloy with 15-percent zinc or more and gray cast iron components and exposed to an internal environment of air/gas – wetted, the applicant stated that the design and operating characteristics of the components and fittings are such that they are normally dry and not
subject to significant amounts of moisture or water pooling. Therefore, the applicant does not consider selective leaching to be an applicable aging effect,

The staff finds the applicant's response acceptable because the applicant assessed the design and operating conditions to determine if the potential for significant water accumulation exists. In cases where the applicant determined that such a potential exists, it included the components within the Selective Leaching program, and will manage the aging of these components. The staff's evaluation of the applicant's revision to LRA Tables 3.3.2-8 and 3.3.2-14, as corrected by letter dated March 30, 2012, is documented in SER Sections 3.3.2.3.8 and 3.3.2.3.14, respectively. The staff's evaluation of the Selective Leaching program is documented in SER Section 3.0.3.1.13. The staff's concern described in RAI 3.2.2.1.1-3 is resolved.

3.3.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.3.1 items 3.3.1.10, 3.3.1-17, 3.3.1-18, 3.3.1-27, 3.3.1-28, 3.3.1-29, 3.3.1-30x, 3.3.1-48, 3.3.1-51, 3.3.1-68, 3.3.1-73, 3.3.1-74, 3.3.1-75, 3.3.1.77, 3.3.1-93, 3.3.1-101, 3.3.1-103, 3.3.1-104, 3.3.1-105, 3.3.1-110, 3.3.1-111, 3.3.1-122, and 3.3.1-123, the applicant claimed that they were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable for these items.

For LRA Table 3.3.1 items 3.3.1-7, 3.3.1-8, 3.3.1-9, 3.3.1-115, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to PWRs. The staff reviewed the SRP-LR, confirmed these items only apply to PWRs, and finds these items are not applicable to LGS.

LRA Table 3.3.1, item 3.3.1-11 addresses steel high-strength high-pressure pump closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage cracking caused by SCC and cyclic loading for this component group. The applicant stated that this item is not applicable because it only applies to PWR plants. The staff noted that the GALL Report, Table VII. E1, item AP-122, addresses high-pressure pump closure bolting in a chemical volume and control system (PWR) and that the reactor water cleanup recirculation pump is equivalent to a charging pump at a PWR. The staff noted that in LRA Table 3.3.2-21, reactor water cleanup system, bolting is managed for loss of material and loss of preload, but not cracking caused by SCC and cyclic loading; however, based on a review of the UFSAR, the staff was able to confirm that the reactor water cleanup recirculation pumps do not use high-strength bolting and thus the bolts are not susceptible to SCC.

LRA Table 3.3.1, item 3.3.1-13 addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of material caused by general corrosion for this component group. The applicant stated that this item is not applicable because there is no steel closure bolting exposed to air with steam or water leakage in the auxiliary systems. The staff evaluated the applicant's claim and found it acceptable because all auxiliary system bolting exposed to air is being managed for loss of material by the Bolting Integrity program using item LRA Table 3.3.1, item 3.3.1-12, the External Surfaces Monitoring of Mechanical Components program using LRA Table 3.3.1, item 3.3.1-78, or the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program using LRA Table 3.5.1, item 3.5.1-80. These programs conduct periodic visual inspections capable of detecting loss of material because of general corrosion in bolting, and the External Surfaces Monitoring of Mechanical Components and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling System programs conduct the visual inspections on a frequency that meets or is more frequent than the Bolting Integrity program, or in the case of infrequently used cranes, bolting is inspected before use; therefore, use of these programs is consistent with the GALL Report.

LRA Table 3.3.1, items 3.3.1-23 and 3.3.1-24 address aluminum piping, piping components, and piping elements exposed to treated water. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry" and XI.M32, "One-Time Inspection" to manage loss of material caused by pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because this material-environment-aging effect combination is addressed with LRA item 3.3.1-25. The staff evaluated the applicant's claim and found it acceptable because the staff confirmed that aluminum piping components exposed to treated water in the auxiliary systems reference LRA item 3.3.1-25, which manages for loss of material in a manner consistent with LRA items 3.3.1-23 and 3.3.1-24 and the GALL Report recommendations.

LRA Table 3.3.1, item 3.3.1-26 addresses steel (with elastomer lining), steel (with elastomer lining or stainless steel cladding) piping, piping components, and piping elements exposed to treated water. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection" to manage loss of material caused by pitting and crevice corrosion (only for steel after lining or cladding degradation) for this component group. The applicant stated that this item is not applicable because this item for the loss of material in lined or clad steel exposed to treated water after elastomer lining or stainless steel cladding degradation was not used. Elastomer lining was not credited for preventing the loss of material aging effect in steel and stainless steel cladding was not assumed to fail because of degradation. The staff evaluated the applicant's claim and found it acceptable for elastomer lined piping because the applicant cited LRA Table 3.3.1, item 3.3.1-21 to manage all steel piping, piping components, and piping elements exposed to treated water, this item recommends the same two programs to manage the components as LRA Table 3.3.1, item 3.3.1-26 (i.e., GALL Report AMPs XI.M2 and XI.32), and the staff confirmed that all steel piping, piping components, and piping elements within the scope of license renewal and exposed to treated water in the auxiliary systems are being managed for loss of material by GALL Report AMPs XI.M2 and XI.32 (i.e., LRA Tables 3.3.2-1, 3.3.2-5, 3.3.2-11 3.3.2-17 3.3.2-18, 3.3.2-19, 3.3.2-21, 3.3.2-24, and 3.3.2-26). The staff evaluated the applicant's claim and found it acceptable for stainless steel clad piping because the applicant cited LRA Table 3.3.1, item 3.3.1-25 to manage all stainless steel piping, piping components, and piping elements exposed to treated water, this item recommends the same two programs to manage the components as item 3.3.1-26 (i.e., GALL Report AMPs XI.M2 and XI.32), this item includes steel with stainless steel cladding materials, and the staff confirmed that all in-scope stainless steel piping, piping components, and piping elements exposed to treated water in the auxiliary systems are being managed for loss of material by GALL Report AMPs XI.M2 and XI.32 (i.e., LRA Tables 3.3.2-1, 3.3.2-5, 3.3.2-11 3.3.2-17 3.3.2-18, 3.3.2-19, 3.3.2-21, 3.3.2-24, and 3.3.2-26).

LRA Table 3.3.1, items 3.3.1-30, 3.3.1-31, and 3.3.1-32 address concrete, reinforced concrete, and cementitious material piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to manage changes in material properties and cracking caused by aggressive chemical attack and cracking caused by settling for these material groups. The applicant stated that these items are not applicable because these aging effects do not apply to the associated components in the auxiliary systems. Since the applicant used item 3.3.1-33, which addresses concrete and cementitious piping components exposed to raw water for loss of material, it was not clear to the staff how the applicant concluded that changes in material properties and cracking did not need to be managed. By letter dated February 14, 2012, the staff issued RAI 3.3.1.30-1 requesting the applicant to provide its bases for claiming items 3.3.1-30, 3.3.1-31, and 3.3.1-32 were not applicable to LGS.

In its response dated March 13, 2012, the applicant stated that the cement material included in item 3.3.1-33 is described in Note 5 of LRA Table 3.3.2-9 as the lining of piping used in the buried fire protection system, which is 12-inch cement lined cast iron pipe. The response also stated that the aging management of the cement lining was revised in response to RAI 3.3.1.33-1 to be part of the Fire Water System program. The response further stated there is no reinforced concrete or asbestos cement piping in scope for license renewal, so item 3.3.1-32 is not applicable. The applicant's response was acceptable because the cement lining material, which is addressed in items 3.3.1-30 and 3.3.1-31, is being managed through the Fire Water System program, which includes flow testing, visual inspections, or volumetric examinations as well as preventive measures capable of managing the applicable aging effects. In addition, the response clarified that the there is no reinforced concrete or asbestos cement piping in scope for license renewal. Based on the above, the staff finds the applicant's determination acceptable, and the staff's concern described in RAI 3.3.1.30-1 is resolved.

LRA Table 3.3.1, items 3.3.1-34, 3.3.1-35, and 3.3.1-37 address copper-alloy and steel piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System" to manage loss of material caused by general, pitting, crevice, and MIC for this component group. The applicant stated that these items are not applicable because these component groups are addressed with LRA items 3.3.1-36 and 3.3.1-38. The staff noted that LRA items 3.3.1-36 and 3.3.1-38 are similar to items 3.3.1-34, 3.3.1-35, and 3.3.1-37, but in some cases manage for the additional aging effects of galvanic corrosion and fouling that leads to corrosion. With respect to item 3.3.1-37, the applicant stated that coatings and linings in carbon steel piping are not credited for mitigating loss of material for license renewal and the staff did not identify any carbon steel piping components in auxiliary systems with either linings or coatings. The staff evaluated the applicant's claim and found it acceptable because the staff confirmed that carbon steel and copper-alloy piping components exposed to raw water in the auxiliary systems reference either LRA item 3.3.1-36 or 3.3.1-38, which manage for loss of material in a manner consistent with LRA items 3.3.1-34, 3.3.1-35 and 3.3.1-37, and the GALL Report recommendations.

LRA Table 3.3.1, item 3.3.1-39 addresses stainless steel piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System" to manage loss of material caused by pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because these component groups are addressed with LRA Table 3.3.1, item 3.3.1-40. The staff noted that LRA Table 3.3.1 item 3.3.1-40 is similar to item 3.3.1-39, but also manages for the additional aging effects of fouling that leads to corrosion. The staff evaluated the applicant's claim and found it acceptable because the staff confirmed that stainless steel piping components exposed to raw water in the auxiliary systems reference LRA item 3.3.1-40, which manage for loss of material in a manner consistent with LRA item 3.3.1-39 and the GALL Report recommendations.

LRA Table 3.3.1, items 3.3.1-43 and 3.3.1-44 address stainless steel piping, piping components, and piping elements and stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water greater than 60° C (greater than 140 °F). The GALL Report recommends GALL Report AMP XI.M21A, "Closed Treated Water Systems" to manage cracking caused by SCC for this component group. The applicant stated that this item is not applicable because there are no stainless steel or steel with stainless steel cladding piping and heat exchanger components exposed to closed-cycle cooling water greater than 60° C (greater than 140 °F) in the auxiliary systems. The staff's review of the LRA and UFSAR was not able to verify the applicant's claim of non-applicability. As documented in SER Section 3.0.3.2.5, the staff issued RAI B.2.1.13-1 requesting the applicant to clarify whether the temperatures of the closed-cycle cooling water environments are above or below the SCC threshold of 60° C (140 °F). In its response dated February 15, 2012, the applicant stated that stress corrosion cracking is not applicable, because the temperature of the closed-cycle cooling water environment is below 60° C (140 °F) for all of the systems managed by the Closed Treated Water Systems program. The staff finds the applicant's claim of non-applicability acceptable because the applicant confirmed that the environment of closed-cycle cooling water greater than 60° C (greater than 140 °F) is not present at LGS.

LRA Table 3.3.1, item 3.3.1-47 addresses stainless steel and steel with stainless steel cladding heat exchanger components exposed to closed-cycle cooling water. The GALL Report recommends GALL Report AMP XI.M21A, "Closed Treated Water Systems" to manage loss of material caused by MIC for this component group. The applicant stated that this item is not applicable because this component group is addressed with LRA Table 3.3.1, item 3.3.1-49. The staff confirmed that the subject components reference LRA item 3.3.1-49, which addresses stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water and manages for loss of material caused by pitting and crevice corrosion with the Closed Treated Water Systems program. The staff noted that, although items 3.3.1-47 and 3.3.1-49 cite different aging mechanisms, the loss of material aging effect and the AMP are identical. The staff also noted that the visual inspection activities in the Closed Treated Water Systems program are capable of, and appropriate for, the detection of pitting, crevice, and MIC before loss of intended function. The staff further noted that EPRI Report 1007820, Closed Cooling Water Chemistry Guideline, Revision 1, states that the regions of heat exchangers most prone to pitting and crevice corrosion (lower tubes that may experience crud buildup) are also those areas where MIC may be expected to occur, and thus targeted inspection locations for pitting, crevice corrosion, and MIC are expected to be similar. The staff evaluated the applicant's claim and finds it acceptable because the applicant's selection of the alternative item 3.3.1-49 will manage for loss of material in a manner consistent with LRA item 3.3.1-47 and the GALL Report recommendations.

LRA Table 3.3.1, item 3.3.1-79 addresses copper-alloy piping, piping components, and piping elements exposed externally to condensation. The GALL Report recommends GALL Report AMP XI.M36 "External Surfaces Monitoring of Mechanical Components" to manage loss of material caused by general, pitting, and crevice corrosion for this component group. The LRA states that this item is not applicable because the only copper alloy components exposed to an external wetted environment are cooling coils in the ventilation system, which are inspected during the internal inspection of the cooler assembly. The LRA also states that management of the cooling coils is addressed by LRA Table 3.3.1, item 3.3.1-89, which is for copper alloy components exposed internally to condensation that are being managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff evaluated the applicant's claim and finds it acceptable because the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and the External Surfaces Monitoring of Mechanical Components programs both propose to manage loss of material using visual inspections capable of detecting aging before loss of intended function.

LRA Table 3.3.1, item 3.3.1-96 addresses elastomers, elastomer seals, and components exposed internally to indoor, uncontrolled air. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components" to manage loss of material caused by wear for this component group. The applicant stated that this item is not applicable because there are no elastomer seals or components exposed to indoor, uncontrolled air with a loss of material aging effect in the auxiliary systems. The GALL Report Section IX.F, states that there are three factors to consider that could cause age-related wear caused by the design of a elastomeric joint, including (1) relative motion between two surfaces under the influence of hard abrasive particles, (2) frequent manipulation, or (3) in clamped joints where relative motion is not intended but may occur caused by a loss of the clamping force. The staff noted that the applicant has many elastomeric components that are exposed to indoor, uncontrolled air or internally to wetted air or gas including hoses, ducting and components, flexible connections, and expansion joints. The staff found the applicant's position acceptable for hoses and ducting and components because:

- All components are being managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components programs.
- LRA Sections B.2.1.26, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, and B.2.1.25, External Surfaces Monitoring of Mechanical Components, state that elastomeric materials will be visually inspected and physically manipulated to detect hardening and loss of strength.
- Although loss of material caused by wear is not listed as an aging effect, the applicant is inspecting for hardening and loss of strength. The visual and physical manipulation inspections can detect loss of material caused by wear.

The staff found the applicant's position acceptable for flexible connections because:

- All components are being managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and External Surfaces Monitoring of Mechanical Components programs.
- LRA Sections B.2.1.26, Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and B.2.1.25, External Surfaces Monitoring of Mechanical Components state that elastomeric materials will be visually inspected and physically manipulated to detect hardening and loss of strength.
- Loss of material is listed as an aging effect for both the internal and external surfaces, although item 3.3.1-96 is not used because the environment is wetted air or gas on internal surfaces, not indoor, uncontrolled air. For the wetted air or gas environment, the applicant did not reference an SRP-LR Table 1 item, but rather cited the item as being

inconsistent and referenced generic note G. The staff's evaluation of the applicant's aging management for these components is documented in SER Section 3.3.2.3.3.

The staff found the applicant's position acceptable for the expansion joints (EDG HTX) because:

- All components are being managed by the Open-Cycle Cooling Water System and External Surfaces Monitoring of Mechanical Components programs.
- LRA Sections B.2.1.12, Open-Cycle Cooling Water System, and B.2.1.25, External Surfaces Monitoring of Mechanical Components, state that elastomeric materials will be visually inspected and physically manipulated to detect hardening and loss of strength.
- Although loss of material caused by wear is not listed as an aging effect, the applicant is inspecting for hardening and loss of strength. The visual and physical manipulation inspections can detect loss of material caused by wear.

LRA Table 3.3.1, item 3.3.1-107 addresses stainless steel piping, piping components and piping elements exposed to soil or concrete. The GALL Report recommends GALL Report AMP XI.M41 "Buried and Underground Piping and Tanks" program to manage loss of material caused by pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because there are no stainless steel piping, piping components, and piping elements exposed to soil in the auxiliary systems and stainless steel piping, piping components, and piping elements exposed to concrete are being managed for aging by item 3.3.1-120. The staff evaluated the applicant's claim and found it acceptable because LRA Tables 3.3.2-11 and 3.3.2-13 contain no stainless steel piping exposed to soil. During the audit, the staff reviewed several drawings and pictures and validated that the applicant has used fillcrete (a cementitious material) as backfill for buried piping, and 3.3.1-120 addresses stainless steel piping, piping components, and piping elements exposed to concrete and is, therefore, an acceptable item to manage this material.

LRA Table 3.3.1, item 3.3.1-108 addresses titanium, super austenitic, aluminum, copper-alloy, and stainless steel piping, piping components, piping elements, and bolting exposed to soil or concrete. The GALL Report recommends GALL Report AMP XI.M41 "Buried and Underground Piping and Tanks" program to manage loss of material caused by pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because there are no titanium, super austenitic, aluminum, or copper-alloy piping, piping components, piping elements, or bolting exposed to soil or concrete in the auxiliary systems. Furthermore, there are no stainless steel piping, piping components, and piping elements exposed to soil in the auxiliary systems, and stainless steel piping, piping components and piping elements exposed to concrete are being managed for aging by item 3.3.1-120. The staff evaluated the applicant's claim and found it acceptable because a review of the UFSAR and LRA confirmed that there are no titanium, super austenitic, aluminum or copper-alloy piping, piping components, or piping elements exposed to soil or concrete within the scope of license renewal, and LRA Tables 3.3.2-11 and 3.3.2-13 contain no stainless steel piping exposed to soil. During the audit, the staff reviewed several drawings and pictures and validated that the applicant has used fillcrete (a cementitious material) as backfill for buried piping, and 3.3.1-120 addresses stainless steel piping, piping components, and piping elements exposed to concrete and is, therefore, an acceptable item to manage this material.

LRA Table 3.3.1, item 3.3.1-109x addresses aluminum, copper-alloy, stainless steel, and steel piping, piping components, and piping elements exposed to an underground environment. The GALL Report recommends GALL Report AMP XI.M41 "Buried and Underground Piping and Tanks" program to manage loss of material caused by general (steel only), pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because loss of material caused by general, pitting, and crevice corrosion of underground steel piping, piping components, and piping elements is addressed in LRA Table 3.3.1, item 3.3.1-80. The staff evaluated the applicant's claim and found it acceptable because a review of the UFSAR and LRA confirmed that there are no in-scope aluminum, copper-alloy, and stainless steel piping, piping components, and piping elements exposed to the underground environment, and 3.3.1-80 addresses steel piping, piping components and piping elements exposed to indoor and outdoor air and uses the Buried and Underground Piping and Tanks program to manage loss of material as recommended by the GALL Report in item 3.3.1-109x.

3.3.2.1.2 Loss of Material

LRA Table 3.3.1, item 3.3.1-12 addresses steel and stainless steel closure bolting exposed externally to condensation and indoor, uncontrolled, and outdoor air that will be managed for loss of material. For the AMR items that cite generic note E, the LRA credits the Buried and Underground Piping and Tanks program to manage the aging effect for carbon and low-alloy steel bolting exposed to outdoor air. The GALL Report recommends GALL Report AMP XI.M18 "Bolting Integrity" to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M18 recommends using periodic inspections of bolting for indication of loss of material and preventive measures such as use of lubricants and proper torque values for installing bolting. The staff noted that the Buried and Underground Piping and Tanks program proposes to manage the aging of carbon and low-alloy steel bolting through the use of coatings as a preventive measure and periodic visual inspections. The staff also noted that in LRA Tables 3.3.2-8 and 3.3.2-22, the carbon and low-alloy steel bolting that cites generic note E is also being managed by the Bolting Integrity program for loss of preload.

The staff's evaluation of the Buried and Underground Piping and Tanks program is documented in SER Section 3.0.3.2.12. In its review of components associated with item 3.3.1-12 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Buried and Underground Piping and Tanks program acceptable because the programs uses coatings as a preventive measure for mitigating external corrosion. Furthermore, periodic visual inspections are capable of detecting loss of material and the same bolting items are being managed by the Bolting Integrity program, which uses preventive measures such as use of lubricants and proper torque values for installing bolting, all of which is consistent with the GALL Report for managing aging of bolting.

The staff concludes that for LRA item 3.3.1-12, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.3 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-25 addresses stainless steel, steel with stainless steel cladding, and aluminum piping, piping components, piping elements, and heat exchanger components exposed to treated water and sodium pentaborate solution that will be managed for loss of material caused by pitting and crevice corrosion. The staff noted that the applicant also applied this item to bolting, tanks, and crane/hoist components.

For the AMR items in LRA Table 3.3.2-10 that reference LRA Table 3.3.1, item 3.3.1-25 and cite generic note E, the LRA credits the Water Chemistry and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems programs to manage the aging effect for aluminum crane/hoist components. The GALL Report recommends GALL Report AMP XI.M2 "Water Chemistry" and XI.M32 "One-Time Inspection" programs to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M32 recommends using a one-time visual or volumetric inspection of components to verify the effectiveness of water chemistry controls and confirm the insignificance of the aging effect. The staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program proposes to manage the aging of the aluminum crane and hoist components through the use of periodic visual inspections in accordance with ASME Code, B30 standards (yearly for frequently used equipment, just before use for infrequently used equipment) to verify the effectiveness of water chemistry controls that mitigate aging.

The staff's evaluations of the Water Chemistry and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.2.6, respectively. In its review of components associated with item 3.3.1-25 in LRA Table 3.3.2-10 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Water Chemistry and Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems programs acceptable because the Water Chemistry program establishes the plant water chemistry control parameters and their limits to mitigate the potential for aging and identifies the actions required if the parameters exceed the limits. Furthermore, the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program prescribes appropriate periodic or before-use visual inspections capable of detecting pitting and crevice corrosion to verify the effectiveness of the water chemistry controls.

For the AMR items in LRA Table 3.3.2-11 that reference LRA Table 3.3.1, item 3.3.1-25 and cite generic note E, the LRA credits the Bolting Integrity program to manage the aging effect for stainless steel bolting. The GALL Report recommends GALL Report AMPs XI.M2, "Water Chemistry," and XI.M32, "One-Time Inspection" to ensure that this aging effect is adequately managed.

GALL Report AMPs XI.M2 and XI.M32 recommend using water chemistry controls and a one-time inspection to verify the effectiveness of those controls to manage aging. The staff noted that, while LRA Section B.2.1.11, Bolting Integrity states that "inspection activities for bolting in a submerged environment are performed in conjunction with associated component maintenance activities," it is not clear how the submerged bolted connections will be inspected and how often inspections will occur. By letter dated February 14, 2012, the staff issued RAI 3.2.2.1.1-1 requesting the applicant to state the parameters that will be inspected during opportunistic inspections of normally submerged bolting, the basis for why these parameters will be capable of assessing the condition of the bolting before loss of intended function occurs, and the minimum number of inspections that will be conducted during the period of extended operation. The applicant's response and the staff's evaluation of that response are documented in SER Section 3.2.2.1.

The staff's evaluation of the Bolting Integrity program is documented in SER Section 3.0.3.2.3. The staff noted that the applicant will visually inspect submerged bolting for loss of material during refueling outages in the fuel pool cooling and cleanup system. The staff also noted that the purity of the water in this system is maintained with filter demineralizers. In its review of components associated with item 3.3.1-25 for which the applicant credited the Bolting Integrity program and cited generic note E, the staff finds the applicant's proposal to manage aging acceptable because the water quality in the submerged environments is maintained to minimize contaminants that could promote corrosion and the periodic visual inspections in the Bolting Integrity program are capable of detecting loss of material before loss of intended function.

The staff concludes that for LRA item 3.3.1-25, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.4 Loss of Material

LRA Table 3.3.1, item 3.3.1-33 addresses concrete and cementitious material piping, piping components, and piping elements exposed to raw water, which will be managed for loss of material due abrasion, cavitation, aggressive chemical attack, and leaching. For the AMR items that cite generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of material for cement piping, piping components, and piping elements exposed to raw water in the fire protection system. The AMR item in LRA Table 3.3.2-9 cites plant-specific note 5, which states that the cement lined piping is the buried fire main.

The GALL Report recommends GALL Report AMP XI.M20, "Open Cycle Cooling Water," to manage loss of material for concrete piping exposed to raw water; however, GALL Report AMP XI.M20 is for components exposed to open-cycle cooling water, not fire water. GALL Report AMP XI.M27, "Fire Water System," manages aging for fire protection system components exposed to fire water and recommends using either flow testing, visual inspections, or volumetric examinations as well as preventive measures including periodic flushes and system performance testing to manage loss of material. System flow testing, flushes, performance testing, and inspections are performed in accordance with the applicable NFPA codes and standards. NFPA 25 includes requirements for flow testing of underground fire mains. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program proposes to use visual inspections to manage loss of material for cement components exposed to raw water and does not include any preventive measures. It is not clear to the staff how the visual inspections performed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program are adequate to manage loss of material for the cement lined buried fire main, given that the program does not include preventive measures or flow testing as recommended by GALL Report AMP XI.M27. By letter dated January 18, 2012, the staff issued RAI 3.3.1.33-1 requesting the applicant to explain how the Inspection of Internal

Surfaces in Miscellaneous Piping and Ducting Components program is adequate to manage loss of material for components exposed to fire water.

In its response dated February 16, 2012, the applicant stated that it will use the Fire Water System program to manage aging for the internal surface of the concrete lining for the fire main. The applicant revised item 3.3.1-33 and the AMR item in LRA Table 3.3.2-9 to reference the Fire Water System program instead of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff's evaluation of the Fire Water System program is documented in SER Section 3.0.3.2.8. The staff finds the applicant's response and its proposal to manage aging for the buried fire main using the Fire Water System program acceptable because the proposed program includes flow testing, visual inspections, or volumetric examinations as well as preventive measures capable of managing loss of material. The staff's concern described in RAI 3.3.1.33-1 is resolved.

The staff concludes that for LRA Table 3.3.1, item 3.3.1-33, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.5 Loss of Material Because of Pitting, Crevice, and Microbiologically Influenced Corrosion

LRA Table 3.3.1, item 3.3.1-41 addresses stainless steel components exposed to raw water that will be managed for loss of material caused by pitting, crevice corrosion, and MIC. For the AMR items that cite generic note E, the LRA credits RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program to manage the aging effects of stainless steel structural bolting, concrete anchors, and concrete embedments for structures and component supports in the spray pond and pump house. The LRA also credits the Structures Monitoring program to manage the aging effects of stainless steel sump liners and integral attachments for structures and component support in the radwaste, reactor, and control enclosures. For this AMR item, the GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure these aging effects are adequately managed.

GALL Report AMP XI.M20 recommends using periodic visual inspections, water chemistry controls, and heat transfer testing to manage aging. However, the staff noted that the applicant's use of item 3.3.1-41 for the associated components may not be appropriate because GALL Report AMP XI.M20 implements the recommendations of GL 89-13 to manage aging of components that transfer heat from safety-related SSCs to the ultimate heat sink. The staff also noted that RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program and the Structures Monitoring program propose to manage the aging of stainless steel components through the use of periodic visual inspections.

The staff's evaluations of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program and the Structures Monitoring program are documented in SER Section 3.0.3.2.18 and Section 3.0.3.2.17, respectively. In its review of components associated with item 3.3.1-41 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the above programs acceptable because both programs perform periodic visual inspections capable of detecting loss of material before loss of function.

The staff concludes that for LRA item 3.3.1-41, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.6 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-56 addresses stainless steel piping components exposed internally to condensation that will be managed for loss of material caused by pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Open-Cycle Cooling Water System program to manage loss of material for stainless steel piping components exposed to wetted air or gas in the safety-related SW system. The GALL Report recommends GALL Report AMP XI.M24, "Compressed Air Monitoring," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M24 recommends maintaining moisture and other corrosive contaminants below acceptable limits by periodic sampling and testing to mitigate loss of material. Additionally, GALL Report AMP recommends periodic and opportunistic visual inspections of accessible internal surfaces to detect signs of loss of material caused by corrosion.

The staff's evaluation of the Open-Cycle Cooling Water System program is documented in SER Section 3.0.3.2.4. This program manages loss of material, reduction of heat transfer, and hardening and loss of strength of elastomers in heat exchangers and piping components in safety-related and nonsafety-related raw water systems exposed to a raw water or wetted air or gas environments. The staff noted that the associated components addressed by item 3.3.1-56 and credit the Open-Cycle Cooling Water System program are stainless steel spray nozzles in the safety-related SW system, which are not part of a compressed air system and do not contain or use compressed air or gas. The staff also noted that these nozzles provide cooling for the emergency SW and RHR SW systems, which are the open-cycle cooling water systems. In its review of components associated with item 3.3.1-56, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System program acceptable because the program includes visual inspections and nondestructive examinations, which are capable of detecting loss of material caused by pitting and crevice corrosion.

The staff concludes that for LRA Table 3.3.1, item 3.3.1-56, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.7 Increased Hardness, Shrinkage, Loss of Strength Because of Weathering

LRA Table 3.3.1, item 3.3.1-57 addresses elastomer fire barrier penetration seals exposed to indoor uncontrolled or outdoor air that will be managed for increased hardness, shrinkage, and loss of strength. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring program to manage the aging effect for elastomer seismic gap fillers and expansion joints. The GALL Report recommends GALL Report AMP XI.M26, "Fire Protection," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M26 recommends performing visual inspections of at least 10 percent of each type of penetration seal every refueling cycle to manage aging for elastomer fire barrier seals. However, GALL Report AMP XI.M26 is only applicable to fire protection system components, and the program activities and inspection frequencies are not applicable for components in other systems. The staff noted that GALL Report AMP XI.S6, "Structures Monitoring," includes aging management of vibration isolators and structural sealants using visual inspections. The staff also noted that the Structures Monitoring program proposes to manage aging of elastomer seals by performing visual inspections of all accessible areas at least once every 10 years.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. In its review of components associated with item 3.3.1-57 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Structures Monitoring program acceptable because it includes visual inspections that are capable of detecting hardness, shrinkage, and loss of strength for seismic gap fillers and expansion joints.

The staff concludes that for LRA item 3.3.1-57, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.8 Loss of Material

LRA Table 3.3.1, item 3.3.1-64 addresses steel and copper-alloy piping, piping components, and piping elements exposed to raw water, which will be managed for loss of material caused by general, pitting, crevice corrosion, and MIC; and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage loss of material for carbon steel piping, piping components, piping elements, tanks, and valve bodies exposed to raw water in the EDG. The LRA also credits RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program to manage loss of material for ductile cast iron and carbon steel concrete embedments exposed to raw water in the spray pond pump house. The LRA further credits the Structures Monitoring program to manage loss of material for carbon steel sump liners, liner anchors, and integral attachments in the turbine enclosure. The GALL Report recommends GALL Report AMP XI.M27, "Fire Water System," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M27 recommends using either flow testing, visual inspections, or volumetric examinations to manage loss of material for fire protection components exposed to raw water. However, GALL Report AMP XI.M27 is only applicable to fire protection system components, and the program activities and inspection frequencies are not applicable for components exposed to raw water in other systems. The Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program, and Structures Monitoring program propose visual inspections to manage loss of material for carbon steel and ductile cast iron components exposed to raw water.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power

Plants, and Structures Monitoring programs are documented in SER Sections 3.0.3.1.16, 3.0.3.2.18, and 3.0.3.2.17, respectively. In its review of components associated with item 3.3.1-64 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program, or Structures Monitoring program acceptable because each program includes visual inspections capable of detecting loss of material in steel components exposed to raw water.

The staff concludes that for LRA item 3.3.1-64, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.9 Loss of Material Caused by General, Pitting, and Crevice Corrosion

LRA Table 3.3.1 item 3.3.1-67 addresses steel tanks exposed externally to outdoor air that will be managed for loss of material caused by general, pitting, and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the Buried and Underground Piping and Tanks program to manage the aging effect for steel tanks. The GALL Report recommends GALL Report AMP XI.M29, "Aboveground Metallic Tanks," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M29 recommends using periodic visual inspections of the external surfaces of the component and coatings as a preventive action to manage aging. The staff noted that the Buried and Underground Piping and Tanks program proposes to manage the aging of steel tanks through the use of periodic visual inspections of the external surfaces of the component and coatings as a preventive action.

The staff's evaluation of the Buried and Underground Piping and Tanks program is documented in SER Section 3.0.3.2.12. The staff noted that the applicant cited plant-specific note 1, which states that the fuel oil storage tanks are located underground in the diesel oil storage tank structures in an outdoor air environment. The staff also noted that, based on a review of the UFSAR and drawings during the audit, the enclosures are not routinely exposed to rain or other forms of moisture despite the stated outdoor air environment given that they are within an enclosed structure. The staff further noted that the inspection interval for the LRA Buried and Underground Piping and Tanks program is once every 10 years and the interval for GALL Report AMP XI.M29, "Aboveground Metallic Tanks," is once a refueling outage; however, given that the tanks are in an underground vault and not exposed to rain or other moisture, the staff finds the inspection interval acceptable. In its review of components associated with item 3.3.1-67 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Buried and Underground Piping and Tanks program acceptable because the tanks are coated as a preventive action and the program includes periodic visual inspections that can detect loss of material.

The staff concludes that for LRA item 3.3.1-67 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.10 Loss of Material Caused by General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-69 addresses copper-alloy piping, piping components, and piping elements exposed to fuel oil, which will be managed for loss of material caused by general, pitting, crevice, and microbiologically-influenced corrosion. For the AMR item that cites generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effect for copper alloy valves. The SRL-LR recommends GALL Report AMP XI.M30, "Fuel Oil Chemistry," and XI.M32, "One-Time Inspection," to ensure that these aging effects are adequately managed.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff noted that in its response to RAI B.2.1.26-2, dated February 15, 2012, the applicant stated, the environment associated with these components is dirty fuel oil, which has similar attributes to the waste water environment, which is monitored by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. GALL Report Section IX.D states that the waste water environment contains contaminants, including oil and boric acid In its review of components associated with item 3.3.1-69 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the applicant has appropriately associated the fuel oil dirty drains as a waste water environment in that both oil and water are present in this piping, and GALL Report item AP-281 recommends that steel exposed to waste water be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program for loss of material.

3.3.2.1.11 Loss of Material Caused by General, Pitting, and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-70 addresses copper-alloy piping, piping components, and piping elements exposed to fuel oil, which will be managed for loss of material caused by general, pitting, crevice, and microbiologically-influenced corrosion. For the AMR item that cites generic note E, the LRA credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to manage the aging effect for copper alloy valves. The SRL-LR recommends GALL Report AMP XI.M30, "Fuel Oil Chemistry," and XI.M32, "One-Time Inspection," to ensure that these aging effects are adequately managed.

The staff noted that although the SRP-LR recommends the use of GALL Report AMP XI.M30, the staff evaluated the acceptability of not using the mitigative and condition monitoring aspect of this program because the components are associated with the dirty fuel oil drain piping in the emergency diesel generator system. This evaluation is documented in SER Section 3.0.3.1.16.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff noted that in its response to RAI B.2.1.26-2, dated February 15, 2012, the applicant stated that the environment associated with these components is dirty fuel oil, which has similar attributes to the waste water environment, which is monitored by the Internal Surfaces in Miscellaneous Piping and Ducting Components program. GALL Report Section IX.D states that the waste water environment contains contaminants, including oil and boric acid. In its review of components associated with item 3.3.1-70 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because: (a) the applicant has appropriately associated the fuel oil dirty drains as a waste water environment in that both oil and water are present in this piping, and (b) GALL Report item AP-281 recommends that steel exposed to waste water be managed by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program for loss of material.

3.3.2.1.12 Hardening and Loss of Strength Because of Elastomer Degradation

LRA Table 3.3.1 item 3.3.1-76 addresses elastomers, elastomer seals, and components exposed to indoor, uncontrolled air that will be managed for hardening and loss of strength caused by elastomer degradation. For the AMR item that cites generic note E, the LRA credits the Structures Monitoring program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M36 recommends using periodic, not to exceed one refueling cycle, visual and physical manipulation inspection techniques to manage aging. The staff noted that the Structures Monitoring program proposes to manage the aging of elastomers, elastomer seals, and components through the use of visual inspection techniques on a not to exceed 5-year inspection frequency. The staff also noted that plant procedures will be enhanced (Enhancement No. 9) to include physical manipulation to detect hardening when a vibration isolation function is suspect; however, it does not state that structural seal inspections will be augmented with physical manipulation.

In its review of components associated with item 3.3.1-76 for which the applicant cited generic note E, the staff lacked sufficient information to complete its evaluation. The inspection interval stated in the Structures Monitoring program is not to exceed 5 years; however, GALL Report AMP XI.M36 recommends that inspections occur on a frequency not to exceed one refueling cycle. In addition, Enhancement No. 9 does not include physical manipulation of structural seals. By letter dated January 18, 2012, the staff issued RAI 3.3.2.1.13-1 requesting the applicant to state the basis for why inspections conducted on a not to exceed 5-year interval will be sufficient to detect hardening and loss of strength in compressible joints and seals (including inflatable pool seals and gate seals) and state whether physical manipulation of elastomeric compressible joints and seals is included in the Structures Monitoring program, or state the basis for how hardening and loss of strength will be detected without physical manipulation.

In its response, dated February 16, 2012, the applicant stated that the elastomeric components referenced in the RAI include inflatable pool seals and gate seals consisting of the equipment pit stop log seals, cask pit gate seals, reactor cavity seals, and fuel pool gate and stop log seals, each of which is periodically replaced as a scheduled preventive maintenance activity. These seals will continue to be replaced on a scheduled basis throughout the period of extended operation and are considered to be within the scope of license renewal. They are short-lived components, however, and are, not subject to an AMR. The applicant also revised LRA Table 3.3.1, item 3.3.1-76 and LRA Table 3.5.2-13 to show that the components have been removed from AMR.

The staff finds the applicant's response acceptable because given that the items are periodically replaced as a scheduled preventive maintenance activity, they are not considered to be long-lived and, therefore, are not required to be managed for aging. The staff's concern described in RAI 3.3.2.1.13-1 is resolved.

The staff concludes that for LRA Table 3.3.1, item 3.3.1-76, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.13 Loss of Material

LRA Table 3.3.1, item 3.3.1-78 and 3.3.1-80 addresses carbon steel fire barrier doors and fire barrier penetration seals exposed externally to indoor, uncontrolled, and outdoor air that will be managed for loss of material. The LRA credits the Fire Protection program, and cites generic note E, to manage the aging effect for carbon steel fire barrier doors and penetration seal. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," program to ensure that these aging effects are adequately managed. GALL Report AMP XI.M36 recommends using visual inspections and walkdowns to manage aging.

The staff's evaluation of the Fire Protection program is documented in SER 3.0.3.2.7. The staff noted that the Fire Protection program proposes to manage the aging of carbon steel fire barrier doors and fire barrier penetration seals through the use of periodic visual inspections and functional testing. In its review of components associated with item 3.3.1-78 and 3.3.1-80 for which the applicant credits the Fire Protection program, and cites generic note E, the staff finds the applicant's proposal to manage aging acceptable because the frequency of monitoring and visual inspections is adequate to prevent significant degradation.

The staff concludes that for LRA Table 3.3.1, items 3.3.1-78 and 3.3.1-80 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.14 Loss of Material

LRA Table 3.3.1, item 3.3.1-80 addresses steel heat exchange components, piping and piping components, and piping elements exposed externally to indoor, uncontrolled, and outdoor air. The LRA credits the Buried and Underground Piping and Tanks program to manage the aging effects for carbon steel and gray cast iron valve body, pump casing, piping, piping components, and piping elements located in underground vaults and cites note E for these AMR items. The GALL Report recommends GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," program to ensure that these aging effects are adequately managed. GALL Report AMP XI.M36 recommends using visual inspections and walkdowns to manage aging.

The staff's evaluation of the Buried and Underground Piping and Tanks program is documented in SER Section 3.0.3.2.12. The staff noted that the Buried and Underground Piping and Tanks program proposes to manage the aging of carbon steel and gray cast iron valve body, pump casing, piping, piping components, and piping elements through the use of external coatings for external corrosion control, and inspections of the external surface of the components. In its review of components associated with LRA Table 3.3.1, item 3.3.1-80, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Buried and Underground Piping and Tanks acceptable because the opportunistic visual inspections and inspection activities exceed the recommendations of GALL Report AMP XI.M36.

3.3.2.1.15 Hardening and Loss of Strength Caused by Elastomer Degradation

LRA Table 3.3.1, item 3.3.1-86 addresses elastomers, elastomer linings, elastomer seals, and components exposed to treated borated water, treated water, and raw water that will be managed for hardening and loss of strength caused by elastomer degradation. For the AMR item that cites generic note E, the LRA credits the Structures Monitoring program to manage the aging effect. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M38 recommends using periodic opportunistic visual and physical manipulation inspection techniques to manage aging. The staff noted that the Structures Monitoring program proposes to manage the aging of elastomers, elastomer seals, and components through the use of visual inspection techniques on a not to exceed 5-year inspection frequency. The staff also noted that plant procedures will be enhanced (Enhancement No. 9) to include physical manipulation to detect hardening when a vibration isolation function is suspect; however, it does not state that structural seal inspections will be augmented with physical manipulation.

In its review of components associated with item 3.3.1-86 for which the applicant cited generic note E, the staff lacked sufficient information to complete its evaluation. The staff noted that Enhancement No. 9 does not include physical manipulation of structural seals. By letter dated January 18, 2012, the staff issued RAI 3.3.2.1.13-1 requesting the applicant to state whether physical manipulation of elastomeric compressible joints and seals is included in the Structures Monitoring program, or state the basis for how hardening and loss of strength will be detected without physical manipulation.

In its response, dated February 16, 2012, the applicant stated that the elastomeric components referenced in the RAI include inflatable pool seals and gate seals consisting of the equipment pit stop log seals, cask pit gate seals, reactor cavity seals, and fuel pool gate and stop log seals, each of which is periodically replaced as a scheduled preventive maintenance activity. These seals will continue to be replaced on a scheduled basis throughout the period of extended operation and are considered to be in-scope but short-lived components and, therefore, not subject to an AMR. The applicant also revised LRA Table 3.3.1, item 3.3.1-86 and LRA Table 3.5.2-13 to show that the components have been removed from AMR.

The staff finds the applicant's response acceptable because given that the items are periodically replaced as a scheduled preventive maintenance activity, they are not considered to be long-lived and not required to be managed for aging. The staff's concern described in RAI 3.3.2.1.13-1 is resolved.

The staff concludes that for LRA item 3.3.1-86, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.16 Loss of Material Caused by General, Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-89 addresses carbon steel piping, piping components, and pump casing exposed internally to wetted air or gas that will be managed for loss of material caused by general, pitting, and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the Open-Cycle Cooling Water System program to manage the aging effect for carbon steel piping, piping components, and pump casing. The GALL Report recommends GALL Report AMP Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M38 recommends using visual inspections during periodic system and component surveillances, or maintenance activities when the surfaces are made accessible. The program uses standardized monitoring and trending activities to track degradation and identifies any abnormal surface condition as an indication of an aging effect for metals. The staff noted that the Open-Cycle Cooling Water System program proposes to manage the aging of piping, piping elements, and piping components of components in nonsafety-related raw water systems through the use of periodic inspections consistent with GL 89-13 in raw water cooling systems. The staff also noted that this program uses condition monitoring to manage the aging effect of loss of material.

The staff's evaluation of the Open-Cycle Cooling Water System program is documented in SER Section 3.0.3.2.4. In its review of components associated with item 3.3.1-89, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Open-Cycle Cooling Water System program acceptable because the program includes visual periodic inspections and NDEs that are capable of detecting loss of material caused by general, pitting, and crevice corrosion.

The staff concludes that for LRA item 3.3.1-89, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.17 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Table 3.3.1, item 3.3.1-92 addresses aluminum piping, piping components, and piping elements exposed internally to condensation that will be managed for loss of material caused by pitting and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Compressed Air Monitoring program to manage the aging effect for aluminum alloy piping, piping components, and piping elements exposed to wetter air or gas in the primary containment instrument gas system. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to ensure that these aging effects are adequately managed.

GALL Report AMP XI.M38 recommends using periodic opportunistic visual inspections of the internal surfaces to manage aging. The staff noted that the Compressed Air Monitoring program includes testing and inspection of the compressed air, primary containment instrument gas, and traversing in-core probe systems within the scope of license renewal and that the effects of corrosion and presence of contaminants are detected during system manager walkdowns, weekly surveillances, and preventive maintenance inspections of compressors, filters, accumulators, receivers, and drain traps. Additionally, the Compressed Air Monitoring program specifies maintaining moisture and other corrosive contaminants below acceptable limits through periodic samples and testing to mitigate loss of material.

The staff's evaluation of the Compressed Air Monitoring program is documented in SER Section 3.0.3.1.9. In its review of components associated with item 3.3.1-92, for which the applicant cited generic note E, the staff did not have sufficient information to determine whether any of the preventive maintenance inspections of the Compressed Air Monitoring program will be conducted on aluminum alloy piping, piping components, and piping elements exposed to wetted air or gas. By letter dated January 18, 2012, the staff issued RAI 3.3.2.1.14-1 requesting the applicant to state whether any of the preventive maintenance inspections of the Compressed Air Monitoring program will be conducted on aluminum alloy piping, piping components, and piping elements exposed internally to wetted air or gas, and, if not, to justify the use of the program for managing loss of materials for these aluminum items.

In its response, dated February 16, 2012, the applicant stated that preventative maintenance inspections are conducted on aluminum alloy piping, piping components, and piping elements exposed internally to wetted air or gas as part of the Compressed Air Monitoring program. The applicant further stated that the Compressed Air Monitoring program will perform periodic and opportunistic visual inspections of internal surfaces of components for signs of corrosion and abnormal corrosion products that indicate a loss of material.

The staff finds the applicant's response acceptable because the Compressed Air Monitoring program includes periodic and opportunistic visual inspections consistent with GALL Report AMP XI.M38 and these inspections are capable of detecting loss of material caused by pitting and crevice corrosion. The staff's concern described in RAI 3.3.2.1.14-1 is resolved.

The staff concludes that for LRA item 3.3.1-92, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.18 Loss of Material Caused by General, Pitting, Crevice, and Microbiologically Influenced Corrosion

LRA Table 3.3.1 item 3.3.1-106 addresses steel (with coating or wrapping) piping, piping components, and piping elements exposed to soil or concrete that will be managed for loss of material caused by general, pitting, crevice corrosion, and MIC. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring program to manage the aging effect for steel (with coating or wrapping) piping, piping components, and piping elements. The GALL Report recommends GALL Report AMP XI.M41, "Buried and Underground Piping and Tanks," program to ensure that these aging effects are adequately managed. The staff noted that the applicant stated that the Structures Monitoring program will be used to manage the aging of the carbon steel and galvanized penetration sleeves in the diesel oil storage tank structures.

GALL Report AMP XI.M41 recommends using protective coatings, cathodic protection and backfill that is not deleterious to the pipe or pipe coatings to manage aging. GALL Report AMP XI.M41, Table 4a, footnote 6 states, "No inspections are necessary if all the piping constructed from the material under consideration is fully backfilled using controlled low strength material." Based on review of plant drawings and specifications during the audit, and the UFSAR, the penetration sleeves are cathodically protected, coated, and backfilled with fillcrete, a cementitious controlled low-strength material; therefore, no inspections are required by GALL Report AMP XI.M41. The staff noted that the Structures Monitoring program proposes to manage the aging of carbon steel and galvanized penetration sleeves in the diesel oil storage tank structures, as documented in Enhancement No. 11, through the use of opportunistic inspections if excavations occur.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. In its review of components associated with item 3.3.1-106, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Structures Monitoring program acceptable because the opportunistic visual inspections exceed the recommendations of GALL Report AMP XI.M41. Furthermore, the sleeves are coated, cathodically protected, and backfilled with acceptable material.

The staff concludes that for LRA item 3.3.1-106, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.3.2.1.19 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed were not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed were not applicable are not applicable to LGS Units 1 and 2.

As discussed in SER Section 3.0.2.2, for those AMRs that the applicant claimed consistency with the GALL Report, the staff evaluated the applicant's claim of consistency. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent.

Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.3.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.3.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the auxiliary system components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- cracking caused by SCC and cyclic loading
- cracking caused by SCC
- loss of material caused by cladding breach
- loss of material caused by pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.3.2.2. The staff's review of the applicant's further evaluation follows.

3.3.2.2.1 Cumulative Fatigue Damage

LRA Section 3.3.2.2.1, which is associated with LRA Table 3.3.1, items 3.3.1-1 and 3.3.1-2, addresses how steel cranes structural girders exposed to indoor, uncontrolled air, and steel and stainless steel piping, piping components, piping elements, and heat exchanger components exposed to indoor, uncontrolled air, treated borated water or treated water are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that fatigue TLAA identified for Class 2 and 3 piping are discussed in LRA Section 4.3, and the evaluation of crane load cycles as a TLAA for cranes is discussed in LRA Section 4.6.

The staff reviewed LRA Section 3.3.2.2.1 against the criteria in SRP-LR Section 3.3.2.2.1, which states that fatigue of these auxiliary system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with 10 CFR 54.21(c)(1) and SRP-LR Sections 4.3 and 4.7. The staff also reviewed the AMRs items associated with LRA Section 3.3.2.2.1 and found that the AMR results are consistent with the GALL Report and SRP-LR.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.3.2.2.1 criteria. For those items that apply to LRA Section 3.3.2.2.1, the staff determined that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Sections 4.3 and 4.6 document the staff's review of the applicant's evaluation of the TLAA for these components.

3.3.2.2.2 Cracking Caused by Stress Corrosion Cracking and Cyclic Loading

LRA Section 3.3.2.2.2, associated with LRA Table 3.3.1, item 3.3.1-3, addresses cracking in stainless steel heat exchanger components exposed to treated borated water. The applicant stated that this item is not applicable because item 3.3.1-3 applies to PWRs. The staff evaluated the applicant's claim and finds it acceptable because treated borated water only applies to PWRs and the applicant is managing cracking of stainless steel heat exchanger components exposed to treated water through item 3.3.1-20, which applies to BWRs.

3.3.2.2.3 Cracking Caused by Stress Corrosion Cracking

LRA Section 3.3.2.2.3, associated with LRA Table 3.3.1, item 3.3.1-4 addresses stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air, which will be managed for stress corrosion cracking. The criteria in the SRP-LR states that either the applicant justifies that the aging effect is not applicable by describing the outdoor air environment present at the plant and demonstrating that stress corrosion cracking is not expected, or GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is used to manage cracking caused by SCC for this component group. The applicant addressed the further evaluation criteria of the SRP-LR by stating that, "SCC of stainless steels exposed to outdoor air and contaminants is considered plausible only if the material temperature is above 140 °F. For the Auxiliary Systems, the outdoor stainless steel components are less than 140 °F."

In its review of components associated with item 3.3.1-4, the staff noted that the environment is periodically subject to wetting (e.g., condensation, rain) which could introduce halides (e.g., cooling tower drift), which are known to contribute to SCC. LRA Section 2.4.7 further states that two circulating water chlorine and acid feed enclosures are used to maintain the chemical properties of the cooling tower basins, which can also contribute to halides in condensation. By letter dated January 17, 2012, the staff issued RAI B.2.1.25-1, requesting that the applicant provide technical justification as to why the LRA AMP does not consider SCC to be an aging effect requiring management for the stainless steel components in the auxiliary systems that are subjected to wet external environments.

In its response dated February 15, 2012, the applicant stated that although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant, a review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components, and recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition. The applicant revised its response to the further evaluation criteria of the SRP-LR by stating that this item is not applicable because LGS is located more than 80 miles from the Atlantic coast and major transportation routes near the site are at least a mile away.

The staff does not find the response to RAI B.2.1.25-1 to be acceptable because experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steels exposed to an outdoor air environment can crack at temperatures as low as 104 to 120 °F, depending on humidity, component surface temperature, and contaminant concentration and composition. The staff noted that while the experimental studies demonstrated that cracking can occur in 4 to 52 weeks, the industry operating experience failures did not necessarily occur early in plant life and therefore, the staff cannot conclude that recent inspections are sufficient to demonstrate an aging effect will not occur during the period of extended operation. By letter dated June 12, 2012, the staff issued followup RAI B.2.1.25-1.1 requesting that the applicant state the basis for why the chemical compounds in the cooling tower plume cannot result in SCC if plume fallout (regardless of prevailing wind direction) accumulates on the external surfaces of stainless steel piping within the scope of license renewal and why chloride contamination is not expected to accumulate on stainless steel components within the scope of license renewal from the soil or nearby agricultural and industrial sources.

In its response dated June 19, 2012, the applicant stated that SCC is not likely to occur because local temperatures have not exceeded 104 °F and only exceeded 100 °F on 2 days in the last 10 years. In addition, the applicant stated that they were not in a coastal environment. The applicant did not respond to the potential for chloride contamination arising from agricultural or industrial sources; however, it revised the External Surfaces Monitoring of Mechanical Components program to manage stainless steel components in an outdoor air environment for SCC. The applicant stated that components that are jacketed or located in underground vaults would not be managed for SCC because they are shielded from accumulation of contaminants in the atmosphere. The applicant revised LRA Sections A.2.1.25, B.2.1.25, 3.3.2.1.22, 3.3.2.2.3, and LRA Tables 3.3.1 (item 3.3.1-4), 3.3.2-8, and 3.3.2-22 accordingly.

The staff finds the applicant's response to RAI B.2.1.25-1.1 acceptable because the applicant will manage SCC of stainless steel components exposed to outdoor air using the External Surfaces Monitoring of Mechanical Components program, components that are jacketed or in underground vaults would not be exposed to sufficient quantities of atmospheric chlorides to cause SCC because they are protected from direct fallout by the intervening materials, the visual inspections of this program are capable of detecting SCC, and managing the aging of these AMR items in this manner is consistent with the GALL Report.

3.3.2.2.4 Loss of Material Caused by Cladding Breach

LRA Section 3.3.2.2.4, associated with LRA Table 3.3.1, item 3.3.1-5, addresses loss of material caused by cladding breach in PWR steel charging pump casings with stainless steel cladding exposed to treated borated water. The applicant stated that this item is not applicable because it only applies to PWRs. The staff confirmed that this item is associated only with PWR plants; therefore, the staff finds the applicant's determination acceptable.

3.3.2.2.5 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Section 3.3.2.2.5, associated with LRA Table 3.3.1, item 3.3.1-6, addresses stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air that will be managed for loss of material caused by pitting and crevice corrosion by the External Surfaces Monitoring of Mechanical Components and the Buried and Underground Piping and Tanks programs. The criterion in SRP-LR Section 3.3.2.2.5 item 1 states that loss of material caused by pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. The applicant addressed the further evaluation criteria of the SRP-LR by stating that any visible evidence of loss of material will be evaluated and entered into the CAP. Additionally, the Buried and Underground Piping and Tanks program will be used to manage the loss of material in stainless steel valve bodies located underground in vaults in the safety-related SW system.

The staff's evaluation of the External Surfaces Monitoring of Mechanical Components program is documented in SER Section 3.0.3.1.15 and Underground Piping and Tanks program is documented in SER Section 3.0.3.2.12. The staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components program is acceptable because it provides for management of aging effects through periodic visual inspection of external surfaces for evidence of loss of material. Furthermore, the staff noted that the Buried and Underground Piping and Tanks program proposes to manage aging through the use of external coatings for external corrosion control, the application of cathodic protection, and the quality of backfill used. The staff finds the applicant's proposal to manage aging of stainless steel valve bodies located underground in vaults using the Buried and Underground Piping and Tanks program is acceptable because the opportunistic visual inspections and inspection activities exceed the recommendations of GALL Report AMP XI.M36.

3.3.2.2.6 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.3.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

For LRA Tables 3.3.2-1 through 3.3.2-26, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.3.2-1 through 3.3.2-26, the applicant, by notes F through J, indicated that the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether 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. The staff's evaluation is documented in the following sections.

3.3.2.3.1 Auxiliary Steam – Summary of Aging Management Review – LRA Table 3.3.2-1

The staff reviewed LRA Table 3.3.2-1, which summarizes the results of AMR evaluations for the auxiliary steam system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.2 Closed Cooling Water – Summary of Aging Management Review – LRA Table 3.3.2-2

The staff reviewed LRA Table 3.3.2-2, which summarizes the results of AMR evaluations for the closed cooling water system component groups.

In LRA Table 3.3.2-2, the applicant stated that the carbon steel piping components internally exposed to closed cycle cooling water will be managed for loss of material caused by cavitation erosion by the Closed Treated Water Systems program. The AMR item cites generic note H and plant-specific note 1, which states the loss of material caused by cavitation erosion has been identified in the reactor enclosure cooling water piping. This item was added by letter, dated February 15, 2012, in response to RAI B.2.1.13-2. The plant-specific note also states that the Closed Treated Water Systems program has been enhanced to include periodic NDE to manage this aging mechanism.

The staff noted that this material and environment combination is identified in the GALL Report, that addresses carbon steel piping exposed to closed cycle cooling water and recommends the Closed Treated Water Systems program to manage loss of material; however, the applicant has identified this additional aging effect caused by this unique aging mechanism that requires monitoring activities beyond those in the GALL Report AMP. The applicant addressed the GALL Report identified aging effects for this component, material, and environment combination in AMR items in LRA Table 3.3.2-2.

The staff's evaluation of the Closed Treated Water Systems program is documented in SER Section 3.0.3.2.5. The staff finds the applicant's proposal to manage aging using the above program acceptable because, as discussed in SER Section 3.0.3.2.5, the applicant enhanced the program to include periodic NDE, which is capable of trending loss of material associated with cavitation erosion.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.3 Compressed Air – Summary of Aging Management Review – LRA Table 3.3.2-3

The staff reviewed LRA Table 3.3.2-3, which summarizes the results of AMR evaluations for the Compressed Air component groups.

In LRA Tables 3.3.2-3, 3.3.2-4, 3.3.2-7, 3.3.2-8, 3.3.2-16, 3.3.2-20, and 3.3.2-23, the applicant stated that elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the LRA Table 3.0-1 states that air/gas environments contain significant amounts of moisture where condensation or water pooling may occur. Based on its review of the GALL Report, which states that elastomers exposed to a water environment (e.g., raw water, treated water, and closed cycle cooling water) are subject to loss of material and hardening and loss of strength, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses periodic opportunistic visual inspections in conjunction with manual or physical manipulation of at least 10 percent of the available surface area, which is an appropriate and effective technique for determining aging effects of elastomers.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.4 Control Enclosure Ventilation - Summary of Aging Management Review – LRA Table 3.3.2-4

The staff reviewed LRA Table 3.3.2-4, which summarizes the results of AMR evaluations for the control enclosure ventilation system component groups.

The staff's evaluation for elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas that will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and that cite generic note G, is documented in 3.3.2.3.3.

In LRA Tables 3.3.2-4, 3.3.2-8, and 3.3.2-20, the applicant stated that copper, aluminum, and copper alloy with less than 15 percent zinc, heat exchanger components exposed externally to wetted air or gas will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic note H.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that LRA Table 3.0-1 states that air or gas environments contain significant amounts of moisture where condensation or water pooling may occur. The staff also noted that the applicant also addressed loss of material for this component, material, and environment combination in AMR items in LRA Tables 3.2.2-3, 3.2.2-4, and 3.2.2-5; LRA Tables 3.3.2-1, 3.3.2.-2, 3.3.2-4, 3.3.2-8, 3.3.2-12, 3.3.2-16, 3.3.2-20, and 3.3.2-22; and LRA Table 3.4.2-3. Based on its review of the GALL Report, which states that copper and copper alloy heat exchanger components exposed to water (e.g., closed-cycle cooling water, raw water, and treated water) are subject to the aging effects of loss of heat transfer and loss of material and that aluminum exposed to condensation is subject to loss of material, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff lacked sufficient information to conclude that the applicant's program is adequate to manage these material, environment, and aging combinations because loss of heat transfer is not included within the applicant's AMP. By letter dated January 17, 2012, the staff issued RAI B.2.1.26-1 requesting the applicant to revise the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program to include the program's aging effects of loss of fracture toughness, reduction of heat transfer, and cracking. The applicant is also requested to including the appropriate details such as parameters to be monitored, acceptance criteria, and detection of aging effect elements necessary to support this program's additional aging effects.

In its response, dated February 15, 2012, the applicant stated that LRA AMP B.2.1.26 and LRA UFSAR supplement Section A.2.1.26 were revised (per Enclosure B of the letter) and loss of fracture toughness, reduction of heat transfer, and cracking were added to those LRA Sections. The applicant also stated that loss of fracture toughness is applied to the ASME Class 3, B and C RWCU pump casings that are not applicable to the requirements of GALL Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," because GALL Report AMP XI.M12 only applies to ASME Code, Class 1 components. The applicant also stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will use visual inspections for these components to monitor for cracking, which follows the inspection and monitoring guidelines found to manage this aging effect in GALL Report AMP XI.M12. The applicant also stated that reduction of heat transfer aging effects will be managed for the reactor enclosure and control enclosure ventilation system coolers, and the EDG system combustion air coolers using visual inspections. The applicant also stated that cracking will be managed for stainless steel components in the waste water greater than 140 °F environment. The applicant also stated that these components are in a more aggressive environment than environments addressed by GALL Report AMP XI.M32, One-Time Inspection program; therefore, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and visual inspections will be used to manage the aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.5 Control Rod Drive – Summary of Aging Management Review – LRA Table 3.3.2-5

The staff reviewed LRA Table 3.3.2-5, which summarizes the results of AMR evaluations for the CRD system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.6 Cranes and Hoists – Summary of Aging Management Review – LRA Table 3.3.2-6

The staff reviewed LRA Table 3.3.2-6, which summarizes the results of AMR evaluations for the cranes and hoists component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.7 Emergency Diesel Generator Enclosure Ventilation – Summary of Aging Management Review – LRA Table 3.3.2-7

The staff reviewed LRA Table 3.3.2-7, which summarizes the results of AMR evaluations for the Emergency Diesel Generator Enclosure Ventilation component groups.

The staff's evaluation for elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas that will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and cite generic note G, is documented in 3.3.2.3.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

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

The staff reviewed LRA Table 3.3.2-8, which summarizes the results of AMR evaluations for the EDG component groups.

The staff's evaluation for copper, aluminum, and copper alloy less than 15 percent zinc heat exchanger components exposed externally to wetted air or gas that will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and cite generic note H, is documented in 3.3.2.3.4.

The staff's evaluation for elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas that will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and cite generic note G, is documented in 3.3.2.3.3.

In LRA Table 3.3.2-8, the applicant stated that elastomer hoses exposed internally to lubricating oil will be managed for hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the LRA Table 3.0-1 states that air or gas environments contain significant amounts of moisture where condensation or water pooling may occur. Based on its review of the GALL Report Section IX.C, which states that hardening and loss of strength for elastomers can be induced by elevated temperatures over about 95 °F (35° C), the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program includes visual inspections supplemented with physical and manual manipulation of elastomers, which is a technique that adequately identify if this aging effect is occurring.

In LRA Table 3.3.2-8, the applicant stated there is a TLAA for carbon steel piping, piping components, and piping elements exposed to diesel exhaust that cites generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.2, for these components and material. The staff's evaluation of the fatigue TLAA for ASME Code Section III Class 2 and 3 and ANSI B31.1 components is documented in SER Section 4.3.2.

By letter dated February 15, 2012, LRA Tables 3.3.2-8 and 3.3.2-22 were amended and the applicant stated that for stainless steel piping, piping components, piping elements, spray nozzles, and valve body exposed to outdoor air no AERM or AMP is proposed. The AMR items cite generic note I. Items associated with 3.3.2-8 and 3.3.2-22 cite plant-specific note 6 and 3, which state that based on plant-specific environmental conditions and operating experience, cracking is not an applicable aging effect since outdoor environments are not conducive to SCC.

The staff reviewed the associated items in the LRA to confirm that no aging effect is applicable for this component, material, and environmental combination. The staff's evaluation is documented in SER Section 3.3.2.2.3.

By letter dated March 13, 2012, the applicant revised LRA Table 3.3.2-8 to include copper alloy with 15-percent zinc or more valve bodies internally exposed to wetted air or gas that will be managed for loss of material by the Selective Leaching program. The AMR items cites generic note H and plant-specific note 7, which states, in part, that the component is exposed to an environment containing significant amounts of moisture where condensation or water pooling may occur, resulting in the loss of material caused by selective leaching.

The staff reviewed the associated item in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant also addressed loss of material (caused by general, pitting, and crevice corrosion) for this component, material, and environment combination in AMR items in LRA Table 3.3.2-8 and proposed the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. Based on its review of the GALL Report, which states that copper alloy with 15-percent zinc or more is vulnerable to loss of material caused by general, pitting, or crevice corrosion in moist air environments, and is also susceptible to selective leaching in a raw water environment, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Selective Leaching program is documented in SER Section 3.0.3.1.13. The staff finds the applicant's proposal to manage aging using the Selective Leaching program acceptable because the program will use a one-time inspection, comprising both visual and mechanical techniques of a sample of components to identify and confirm existence of the loss of material because of selective leaching.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

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

The staff reviewed LRA Table 3.3.2-9, which summarizes the results of AMR evaluations for the Fire Protection component groups.

In LRA Table 3.3.2-9, the applicant stated that the soil (asphalt covered) dikes exposed externally to outdoor air will be managed for loss of material or loss of form by the Structures Monitoring program. The AMR item cites generic note F and plant-specific note 1.

Plant-specific note 1 states that this component is a soil dike covered with asphalt, intended to contain oil spills. The aging effects are similar to those in the GALL Report item III.A6.T-22 for earthen water-control structures. The Structures Monitoring program is credited for managing the aging effects for this component.

The staff noted that this material and environment combination are similar to that identified in the GALL Report item III.A6.T-22, which addresses earthen water-control structures exposed to water flowing or standing and recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the Federal Emergency Regulatory Commission (FERC) US Army Corps of Engineers dam inspections and maintenance programs to manage these aging effects. Based on its review of the GALL Report, which identified aging effects for this component, material, and environment combination, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. The staff noted that under the Structures Monitoring program structures and structural components are inspected by qualified personnel in accordance with station procedures that will be enhanced for consistency with ACI 349.3R-02. The staff also noted that the structures and structural components are inspected for indications of deterioration and distress, including evidence of leaching, loss of material, cracking, and loss of bond as identified in ACI 201.1R, "Guide for Making a Condition Survey of Existing Buildings." The staff further noted that the Structures Monitoring program addresses environments of uncontrolled indoor and outdoor air, treated water, raw water, water-flowing, and ground water and soil, and inspections are performed at a frequency not to exceed 5 years. The staff finds the applicant's proposal to manage aging using the Structures Monitoring program acceptable because the soil (asphalt covered) dikes will be managed for loss of material or loss of form through inspections by qualified personnel, at inspection intervals not to exceed 5 years, in accordance with station procedures that have been enhanced for consistency with ACI 349.3R-02.

In LRA Table 3.3.2-9, the applicant stated that Darrmatt, Thermolag, and Cafecote fire barriers exposed externally to uncontrolled indoor air will be managed for loss of material and cracking by the Fire Protection program. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that Darmatt, Thermolag, and Cafecote are typical fire-resistant materials used to provide fire protection for equipment and structures. NUREG-1924 describes Darmatt as a flexible insulating board hydrate fire barrier and Thermolag as an ablative water-based fire barrier that can be a prefabricated board or spray-on fireproofing material. During the audit, the applicant clarified that the Cafecote material referenced in the LRA is also called Cafco. Cafco is a cementitious spray-on fire resistant material (www.isolatek.com/datasheets.asp). Although Darmatt, Thermolag, and Cafco are not specifically mentioned in the GALL Report, AMP XI.M26, "Fire Protection," does state that the program includes management of loss of material and cracking for fire barrier walls, ceilings, floors, and other fire resistant materials, such as flamastic, 3M firewrapping, and spray-on and intumescent coatings. Based on its review of GALL Report AMP XI.M26, NUREG-1924, and industry guidance, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination because Darmatt, Thermolag, and

Cafco have a similar form, function, and composition as the fire-resistant coatings listed in the GALL Report AMP, and, therefore, are subject to the same aging effects.

The staff's evaluation of the Fire Protection program is documented in SER Section 3.0.3.2.7. The staff finds the applicant's proposal to manage aging using the Fire Protection program acceptable because it includes periodic visual inspections that are capable of detecting loss of material and cracking in various fire barrier materials.

In LRA Table 3.3.2-9, the applicant stated there is a TLAA for carbon steel piping, piping components, and piping elements exposed to diesel exhaust that cites generic note H. The staff confirmed that there is a TLAA, as documented in LRA Section 4.3.2, for these components and material. The staff's evaluation of the fatigue TLAA for ASME Code Section III Class 2 and 3 and ANSI B31.1 components is documented in SER Section 4.3.2.

By letter dated February 15, 2012, the applicant amended LRA Table 3.3.2-9 to include alumina silica and gypsum fire barriers exposed externally to uncontrolled indoor air that will be managed for cracking by the Fire Protection program. The AMR items cite generic note F.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that alumina silica and gypsum are typical fire-resistant materials used to provide fire protection for equipment and structures. Although these materials are not specifically mentioned in the GALL Report, AMP XI.M26, "Fire Protection," does state that the program includes management of loss of material and cracking for fire barrier walls, ceilings, floors, and other fire-resistant materials, such as flamastic, 3M firewrapping, and spray-on and intumescent coatings. Based on its review of GALL Report AMP XI.M26, the staff noted that the applicant could have also identified loss of material as an applicable aging effect for this component, material, and environment combination because alumina silica and gypsum have a similar form, function, and composition as the fire-resistant coatings listed in the GALL Report AMP, and, therefore, are subject to the same aging effects. However, the staff also noted that loss of material in alumina silica and gypsum materials would not be caused by the same mechanisms as for metallic components and could be identified using the same inspection methods used to identify cracking.

The staff's evaluation of the Fire Protection program is documented in SER Section 3.0.3.2.7. The staff noted that the Fire Protection program uses visual inspections to identify cracking and that any loss of material would be identified during these visual inspections. The staff finds the applicant's proposal to manage aging using the Fire Protection program acceptable because the program includes periodic visual inspections capable of detecting loss of material and cracking in various fire barrier materials.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.10 Fuel Handling and Storage - Summary of Aging Management Review – LRA Table 3.3.2-10

The staff reviewed LRA Table 3.3.2-10, which summarizes the results of AMR evaluations for the fuel handling and storage component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.11 Fuel Pool Cooling and Cleanup – Summary of Aging Management Review – LRA Table 3.3.2-11

The staff reviewed LRA Table 3.3.2-11, which summarizes the results of AMR evaluations for the Fuel Pool Cooling and Cleanup component groups.

In LRA Table 3.3.2-11, the applicant stated that nickel alloy expansion joints exposed internally to treated water will be managed for loss of material by the Water Chemistry and One-Time Inspection programs. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the Metals Handbook, Volume 13, "Corrosion," which states that nickel alloy materials are not susceptible to cracking at temperatures associated with the spent fuel pool cooling (approximately 140 °F), the staff finds the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluations of the Water Chemistry and One-Time Inspection programs are documented in SER Sections 3.0.3.1.2 and 3.0.3.1.12, respectively. The staff finds the applicant's proposal to manage aging using the above programs acceptable, because the Water Chemistry program maintains contaminants at levels to minimize loss of material caused by corrosion, and the One-Time Inspection program will verify the effectiveness of the Water Chemistry program.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

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

The staff reviewed LRA Table 3.3.2-12, which summarizes the results of AMR evaluations for the nonsafety-related SW system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.13 Plant Drainage – Summary of Aging Management Review – LRA Table 3.3.2-13

The staff reviewed LRA Table 3.3.2-13, which summarizes the results of AMR evaluations for the Plant Drainage component groups.

In LRA Table 3.3.2-13, the applicant stated that stainless steel bolting exposed to wetted air or gas will be managed for loss of preload by the Bolting Integrity program. The AMR item cites generic note H. This item cites plant-specific note 1, which states that the bolting is in the airspace of the reactor enclosure sumps.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant also addressed loss of material for this component, material, and environment combination in AMR items in LRA Table 3.3.2-13. The staff notes that GALL Report item EP-120 states that loss of preload is an appropriate aging effect for stainless steel bolting exposed to treated water, an environment similar to wetted air or gas from a preload perspective, and there are no bolting items for loss of material in a wetted air or gas environment identified in the GALL Report. However, for exposure to soil, an environment that can include moisture, loss of material is listed as an aging effect in the GALL Report. Therefore, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Bolting Integrity program is documented in SER Section 3.0.3.2.3. The staff finds the applicant's proposal to manage aging using the Bolting Integrity program acceptable because the program includes periodic inspections of bolting for loss of preload and preventive measures such as the use of lubricants and proper torque values for installing bolting so that an appropriate preload can be maintained.

In LRA Table 3.3.2-13, the applicant stated that gray cast iron piping, piping components, and piping elements internally exposed to waste water will be managed for loss of material by the Selective Leaching program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant also addressed loss of material (caused by general, pitting, crevice, and MIC) for this component, material, and environment combination in AMR items in LRA Table 3.3.2-13 and proposed the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components is documented in SER Section 3.0.3.1.16. Based on its review of the GALL Report, which states that in certain environments gray cast iron is vulnerable to loss of material caused by general, pitting crevice corrosion, and MIC, and is also susceptible to selective leaching, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Selective Leaching program is documented in SER Section 3.0.3.1.13. The staff finds the applicant's proposal to manage aging using the Selective Leaching program acceptable because the program will use a one-time inspection, comprising both visual and mechanical techniques of a sample of components to identify and confirm existence of the loss of material caused by selective leaching.

In LRA Table 3.3.2-13, the applicant stated that stainless steel piping, piping components, piping elements and valve bodies exposed externally to wetted air or gas will be managed for loss of material by the External Surfaces Monitoring of Mechanical Components program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states that stainless steel components exposed to wetted air or gas should be managed for loss of material, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination..

The staff's evaluation of the External Surface 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 the program includes visual inspections capable of detecting loss of material in stainless components exposed externally to wetted air or gas.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.14 Primary Containment Instrument Gas – Summary of Aging Management Review – LRA Table 3.3.2-14

The staff reviewed LRA Table 3.3.2-14, which summarizes the results of AMR evaluations for the Primary Containment Instrument Gas component groups.

The staff's evaluation for zinc valve bodies exposed to uncontrolled indoor air, which has no aging effect and for which no AMP is proposed, is documented in SER Section 3.2.2.3.2.

In LRA Table 3.3.2-14, the applicant stated that there is no aging effect for zinc valve bodies exposed internally to dry air or gas and no AMP is proposed. The AMR items cite generic note F and plant-specific note 2, which states that zinc die cast has no aging effects in a dry air or gas environment.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable based on its review of the Metals Handbook, Desk Edition, 2nd Edition, which states zinc has a high degree of atmospheric corrosion resistance because of the formation of carbonate films. Also, the GALL Report item V.F.EP-14 states that galvanized (zinc-coated) steel has no aging effect in a controlled indoor air environment, which, like the air/gas-dry environment, is controlled to low humidity levels.

By letter dated March 13, 2012, the applicant revised LRA Table 3.3.2-14 to include gray cast iron piping, piping components, and piping elements internally exposed to wetted air or gas that will be managed for loss of material by the Selective Leaching program. The AMR items cites generic note H and plant-specific note 3, which states, in part, that the component is exposed to an environment containing significant amounts of moisture where condensation or water pooling may occur, resulting in the loss of material caused by selective leaching.

The staff reviewed the associated item in the LRA and considered whether the aging effect proposed by the applicant constitutes all of the credible aging effects for this component, material, and environment description. The staff noted that the applicant also addressed loss of material (caused by general, pitting, and crevice corrosion) for this component, material, and environment combination in AMR items in LRA Table 3.3.2-14 and proposed the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. Based on its review of the GALL Report, which states that gray cast iron is vulnerable to loss of material caused by general, pitting, and crevice corrosion in moist air environments, and is also susceptible to selective leaching in a raw water environment, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Selective Leaching program is documented in SER Section 3.0.3.1.13. The staff finds the applicant's proposal to manage aging using the Selective Leaching program acceptable because the program will use a one-time inspection, comprising both visual and mechanical techniques of a sample of components to identify and confirm existence of the loss of material caused by selective leaching.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.15 Primary Containment Leak Testing – Summary of Aging Management Review – LRA Table 3.3.2-15

The staff reviewed LRA Table 3.3.2-15, which summarizes the results of AMR evaluations for the primary containment leak testing component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.16 Primary Containment Ventilation – Summary of Aging Management Review – LRA Table 3.3.2-16

The staff reviewed LRA Table 3.3.2-16, which summarizes the results of AMR evaluations for the Primary Containment Ventilation component groups.

The staff's evaluation for elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas, which will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and cites generic note G, is documented in 3.3.2.3.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.17 Process Radiation Monitoring – Summary of Aging Management Review – LRA Table 3.3.2-17

The staff reviewed LRA Table 3.3.2-17, which summarizes the results of AMR evaluations for the process radiation monitoring component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.18 Process and Post-Accident Sampling - Summary of Aging Management Review – LRA Table 3.3.2-18

The staff reviewed LRA Table 3.3.2-18, which summarizes the results of AMR evaluations for the Process and Post-Accident Sampling component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.19 Radwaste – Summary of Aging Management Review – LRA Table 3.3.2-19

The staff reviewed LRA Table 3.3.2-19, which summarizes the results of AMR evaluations for the Radwaste component groups.

In LRA Table 3.3.2-19, the applicant stated that stainless steel piping, piping components and piping elements, tanks and valve body exposed internally to waste water greater than 140 °F will be managed for cracking by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states that stainless steel in water environments greater than 140 °F of closed-cycle cooling water, treated borated water, and treated water are subject to cracking, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff lacked sufficient information to conclude that the applicant's program is adequate to manage these materials, environment, and aging combinations because the LRA did not include cracking within the applicant's AMP. By letter dated January 17, 2012, the staff issued RAI B.2.1.26-1 requesting the applicant to revise the LRA AMP to include the program's aging effects of loss of fracture toughness, reduction of heat transfer, and cracking. The applicant is also requested to include the appropriate details such as parameters to be monitored, acceptance criteria, and detection of aging effect elements necessary to support this program's additional aging effects.

In its response, dated February 15, 2012, the applicant stated that LRA AMP B.2.1.26 and LRA UFSAR supplement Section A.2.1.26 were revised (per Enclosure B of the letter) and loss of fracture toughness, reduction of heat transfer, and cracking were added to those sections of the LRA. The applicant also stated that loss of fracture toughness is applied to the ASME Code, Class 3, B and C RWCU pump casings that are not applicable to the requirements of GALL

Report AMP XI.M12, "Thermal Aging Embrittlement of Cast Austenitic Stainless Steel (CASS)," because GALL Report AMP XI.M12 only applies to ASME Code Class 1 components. The applicant also stated that the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will use visual inspections for these components to monitor for cracking that follows the inspection and monitoring guidelines found to manage this aging effect in GALL Report AMP XI.M12. The applicant also stated that reduction of heat transfer aging effect will be managed for the reactor enclosure and control enclosure ventilation system coolers, and the EDG system combustion air coolers using visual inspections. The applicant also stated that cracking will be managed for stainless steel components in the waste water greater than 140 °F environment. The applicant also stated that since these components are in a more aggressive environment than environments addressed by GALL Report AMP XI.M32, "One-Time Inspection" program, the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program will be used and visual inspections will be used to manage the aging effect.

The staff finds the applicant's response acceptable because the applicant has identified all the aging effects that will be addressed by the program, including loss of fracture toughness, reduction of heat transfer, cracking, and the associated program inspections for these aging effects are adequate methods to manage these aging effects. The staff's concern described in RAI B.2.1.26-1 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.20 Reactor Enclosure Ventilation – Summary of Aging Management Review – LRA Table 3.3.2-20

The staff reviewed LRA Table 3.3.2-20, which summarizes the results of AMR evaluations for the Reactor Enclosure Ventilation component groups.

The staff's evaluation for elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas, which will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and that cite generic note G, is documented in 3.3.2.3.3.

The staff's evaluation for copper, aluminum, and copper alloy less than 15 percent zinc, heat exchanger components exposed externally to wetted air or gas, which will be managed for reduction of heat transfer by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and that cite generic note H, is documented in 3.3.2.3.4.
On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.21 Reactor Water Cleanup – Summary of Aging Management Review – LRA Table 3.3.2-21

The staff reviewed LRA Table 3.3.2-21, which summarizes the results of AMR evaluations for the Reactor Water Cleanup component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

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

The staff reviewed LRA Table 3.3.2-22, which summarizes the results of AMR evaluations for the safety-related SW component groups.

By letter dated February 15, 2012, LRA Tables 3.3.2-8 and 3.3.2-22 were amended and the applicant stated that for stainless steel piping, piping components, piping elements, spray nozzles, and valve body exposed to outdoor air no AERM or AMP is proposed. The AMR items cite generic note I. Items associated with 3.3.2-8 and 3.3.2-22 cite plant-specific note 6 and 3, which state that based on plant-specific environmental condition and operating experience, cracking is not an applicable aging effect since outdoor environments are not conducive to SCC.

The staff reviewed the associated items in the LRA to confirm that no aging effect is applicable for this component, material, and environmental combination. The staff evaluation is documented in SER Section 3.3.2.2.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.23 Spray Pond Pump House Ventilation – Summary of Aging Management Review – LRA Table 3.3.2-23

The staff reviewed LRA Table 3.3.2-23, which summarizes the results of AMR evaluations for the Spray Pond Pump House Ventilation component groups.

The staff's evaluation for elastomer hoses, ducting and components, and flexible connections exposed internally to wetted air or gas, which will be managed for loss of material and hardening and loss of strength by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program and that cite generic note G, is documented in 3.3.2.3.3.

The staff reviewed the associated items in the LRA to confirm that this aging effect is not applicable for this component, material, and environment combination. The staff's evaluation is documented in SER Section 3.3.2.2.3.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.3.2.3.24 Standby Liquid Control - Summary of Aging Management Review – LRA Table 3.3.2-24

The staff reviewed LRA Table 3.3.2-24, which summarizes the results of AMR evaluations for the SLC component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.25 Traversing In-core Probe - Summary of Aging Management Review – LRA Table 3.3.2-25

The staff reviewed LRA Table 3.3.2-25, which summarizes the results of AMR evaluations for the traversing in-core probe component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.2.3.26 Water Treatment and Distribution - Summary of Aging Management Review – LRA Table 3.3.2-26

The staff reviewed LRA Table 3.3.2-26, which summarizes the results of AMR evaluations for the Water Treatment and Distribution component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.3.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the auxiliary systems components within the scope of license renewal and subject to an AMR 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 Aging Management of Steam and Power Conversion Systems

This SER Section documents the staff's review of the applicant's AMR results for the steam and power conversion systems components and component groups of:

- circulating water system
- condensate
- condenser and air removal system
- extraction steam system
- feedwater system
- main steam system
- main turbine

3.4.1 Summary of Technical Information in the Application

LRA Section 3.4 provides AMR results for the steam and power conversion systems components and component groups. LRA Table 3.4.1, "Summary of Aging Management Programs for Steam and Power Conversion Systems Evaluated in Chapter VIII of

NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the steam and power conversion systems components and component groups. The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since it was issued.

3.4.2 Staff Evaluation

The staff reviewed LRA Section 3.4 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the steam and power conversion systems components, within the scope of license renewal and subject to an AMR, 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 conducted a review of AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report. However, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.4.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.4.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.4.2.3.

For SSCs that the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to verify the applicant's claims.

Table 3.4-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.4 and addressed in the GALL Report.

Table 3.4-1 Staff Evaluation for Steam and Power Conversion Systems Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to steam or treated water (3.4.1-1)	Cumulative fatigue damage caused by fatigue	Fatigue is a TLAA to be evaluated for the period of extended operation. See the SRP, Section 4.3 "Metal Fatigue," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.4.2.2.1)
Stainless steel piping, piping components, and piping elements; tanks exposed to air-outdoor (3.4.1-2)	Cracking caused by stress corrosion cracking	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with GALL Report (See SER subsection 3.4.2.2.2)
Stainless steel piping, piping components, and piping elements; tanks exposed to air-outdoor (3.4.1-3)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	Yes	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report (See SER subsection 3.4.2.2.3)
Steel external surfaces, bolting exposed to air with borated water leakage (3.4.1-4)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Steel piping, piping components, and piping elements exposed to steam, treated water (3.4.1-5)	Wall thinning caused by flow-accelerated corrosion	Chapter XI.M17, "Flow-Accelerated Corrosion"	No	Flow-Accelerated Corrosion	Consistent with the GALL Report
Steel, stainless steel bolting exposed to soil (3.4.1-6)	Loss of preload	Chapter XI.M18, "Bolting Integrity "	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
High-strength steel closure bolting exposed to air with steam or water leakage (3.4.1-7)	Cracking caused by cyclic loading, stress corrosion cracking	Chapter XI.M18, "Bolting Integrity"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel; stainless steel bolting, closure bolting exposed to air-outdoor (external), air-indoor, uncontrolled (external) (3.4.1-8)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel closure bolting exposed to air with steam or water leakage (3.4.1-9)	Loss of material caused by general corrosion	Chapter XI.M18, "Bolting Integrity"	No	NA	Not applicable to LGS (See SER Section 3.4.2.1.1)
Copper alloy, nickel alloy, steel; stainless steel, steel; stainless steel bolting, closure bolting exposed to any environment, air-outdoor (external), air-indoor, uncontrolled (external) (3.4.1-10)	Loss of preload caused by thermal effects, gasket creep, and self-loosening	Chapter XI.M18, "Bolting Integrity"	No	Bolting Integrity	Consistent with the GALL Report
Stainless steel piping, piping components, and piping elements, tanks, heat exchanger components exposed to steam, treated water >60 °C (>140 °F) (3.4.1-11)	Cracking caused by stress corrosion cracking	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report (see SER Section (3.4.2.1)
Steel; stainless steel tanks exposed to treated water (3.4.1-12)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to treated water (3.4.1-13)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Steel piping, piping components, and piping elements, PWR heat exchanger components exposed to steam, treated water (3.4.1-14)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Steel heat exchanger components exposed to treated water (3.4.1-15)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Copper alloy, stainless steel, nickel alloy, aluminum piping, piping components, and piping elements, heat exchanger components and tubes, PWR heat exchanger components exposed to treated water, steam (3.4.1-16)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Copper alloy heat exchanger tubes exposed to treated water (3.4.1-17)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Copper alloy, stainless steel heat exchanger tubes exposed to treated water (3.4.1-18)	Reduction of heat transfer caused by fouling	Chapter XI.M2, "Water Chemistry," and Chapter XI.M32, "One-Time Inspection"	No	Water Chemistry and One-Time Inspection	Consistent with the GALL Report
Stainless steel, steel heat exchanger components exposed to raw water (3.4.1-19)	Loss of material caused by general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water System	Consistent with the GALL Report
Copper alloy, stainless steel piping, piping components, and piping elements exposed to raw water (3.4.1-20)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (See SER Section 3.4.2.1.1)
Stainless steel heat exchanger components exposed to raw water (3.4.1-21)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	Open-Cycle Cooling Water and Bolting Integrity	Consistent with the GALL Report (see SER Section 3.4.2.1.2)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel, copper alloy, steel heat exchanger tubes, heat exchanger components exposed to raw water (3.4.1-22)	Reduction of heat transfer caused by fouling	Chapter XI.M20, "Open-Cycle Cooling Water System"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to closed-cycle cooling water >60 °C (>140 °F) (3.4.1-23)	Cracking caused by stress corrosion cracking	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-24)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel heat exchanger components exposed to closed-cycle cooling water (3.4.1-25)	Loss of material caused by general, pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Stainless steel heat exchanger components, piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-26)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to closed-cycle cooling water (3.4.1-27)	Loss of material caused by pitting, crevice, and galvanic corrosion	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel, stainless steel, copper alloy heat exchanger components and tubes, heat exchanger tubes exposed to closed-cycle cooling water (3.4.1-28)	Reduction of heat transfer caused by fouling	Chapter XI.M21A, "Closed Treated Water Systems"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel tanks exposed to air-outdoor (external) (3.4.1-29)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel, stainless steel, aluminum tanks exposed to soil or concrete, air-outdoor (external) (3.4.1-30)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	Aboveground Metallic Tanks	Consistent with the GALL Report
Stainless steel, aluminum tanks exposed to soil or concrete (3.4.1-31)	Loss of material caused by pitting, and crevice corrosion	Chapter XI.M29, "Aboveground Metallic Tanks"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Gray cast iron piping, piping components, and piping elements exposed to soil (3.4.1-32)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Gray cast iron, copper-alloy (>15% Zn or >8% Al) piping, piping components, and piping elements exposed to treated water, raw water, closed-cycle cooling water (3.4.1-33)	Loss of material caused by selective leaching	Chapter XI.M33, "Selective Leaching"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel external surfaces exposed to air-indoor, uncontrolled (external), air-outdoor (external), condensation (external) (3.4.1-34)	Loss of material caused by general corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	External Surfaces Monitoring of Mechanical Components	Consistent with the GALL Report
Aluminum piping, piping components, and piping elements exposed to air-outdoor (3.4.1-35)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M36, "External Surfaces Monitoring of Mechanical Components"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel piping, piping components, and piping elements exposed to air-outdoor (internal) (3.4.1-36)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to condensation (internal) (3.4.1-37)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to raw water (3.4.1-38)	Loss of material caused by general, pitting, crevice, galvanic, and microbiologically -influenced corrosion; fouling that leads to corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	NA	Not applicable to LGS (See SER Section 3.4.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to condensation (internal) (3.4.1-39)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components	Consistent with the GALL Report
Steel piping, piping components, and piping elements exposed to lubricating oil (3.4.1-40)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Steel heat exchanger components exposed to lubricating oil (3.4.1-41)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Aluminum piping, piping components, and piping elements exposed to lubricating oil (3.4.1-42)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to lubricating oil (3.4.1-43)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Not applicable	Not applicable to LGS (see SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Stainless steel piping, piping components, and piping elements, heat exchanger components exposed to lubricating oil (3.4.1-44)	Loss of material caused by pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	Lubricating Oil Analysis and One-Time Inspection	Consistent with the GALL Report
Aluminum heat exchanger components and tubes exposed to lubricating oil (3.4.1-45)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Stainless steel, steel, copper alloy heat exchanger tubes exposed to lubricating oil (3.4.1-46)	Reduction of heat transfer caused by fouling	Chapter XI.M39, "Lubricating Oil Analysis," and Chapter XI.M32, "One-Time Inspection"	No	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Steel (with coating or wrapping) piping, piping components, and piping elements; tanks exposed to soil or concrete (3.4.1-47)	Loss of material caused by general, pitting, crevice, and microbiologically -influenced corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	Buried Piping and Underground Piping and Tanks	Consistent with the GALL Report
Stainless steel bolting exposed to soil (3.4.1-48)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to soil or concrete (3.4.1-49)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Steel bolting exposed to soil (3.4.1-50)	Loss of material caused by general, pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Underground stainless steel and steel piping, piping components, and piping elements (3.4.1-50x)	Loss of material caused by general (steel only), pitting and crevice corrosion	Chapter XI.M41, "Buried and Underground Piping and Tanks"	No	NA	Not applicable to LGS (See SER Section 3.4.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel piping, piping components, and piping elements exposed to concrete (3.4.1-51)	None	None, provided 1) attributes of the concrete are consistent with ACI 318 or ACI 349 (low water-to-cement ratio, low permeability, and adequate air entrainment) as cited in NUREG-1557; and 2) plant OE indicates no degradation of the concrete	No, if conditions are met.	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Aluminum piping, piping components, and piping elements exposed to gas, air-indoor, uncontrolled (internal/external) (3.4.1-52)	None	None	NA – No AEM or AMP	NA	Consistent with SRP-LR
Copper-alloy (≤15% Zn and ≤8% Al) piping, piping components, and piping elements exposed to air with borated water leakage (3.4.1-53)	None	None	NA – No AEM or AMP	NA	Not applicable to BWRs (see SER Section 3.4.2.1.1)
Copper-alloy piping, piping components, and piping elements exposed to gas, air-indoor, uncontrolled (external) (3.4.1-54)	None	None	NA – No AEM or AMP	NA	Consistent with SRP-LR
Glass piping elements exposed to lubricating oil, air-outdoor, condensation (internal/external), raw water, treated water, air with borated water leakage, gas, closed-cycle cooling water, air-indoor, uncontrolled (external) (3.4.1-55)	None	None	NA – No AEM or AMP	NA	Consistent with SRP-LR

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in SRP-LR Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Nickel alloy piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external) (3.4.1-56)	None	None	NA – No AEM or AMP	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Nickel alloy, PVC piping, piping components, and piping elements exposed to air with borated water leakage, air-indoor, uncontrolled, condensation (internal) (3.4.1-57)	None	None	NA - No AEM or AMP	NA	Not applicable to LGS (see SER Section 3.4.2.1.1)
Stainless steel piping, piping components, and piping elements exposed to air-indoor, uncontrolled (external), concrete, gas, air-indoor, uncontrolled (internal) (3.4.1-58)	None	None	NA - No AEM or AMP	NA	Consistent with SRP-LR
Steel piping, piping components, and piping elements exposed to air-indoor controlled (external), gas (3.4.1-59)	None	None	NA - No AEM or AMP	NA	Consistent with SRP-LR

The staff's review of the steam and power conversion systems component groups followed any one of several approaches. One approach, documented in SER Section 3.4.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.4.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.4.2.3, reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the steam and power conversion systems components is documented in SER Section 3.0.3.

3.4.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.4.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the steam and power conversion systems components:

- bolting integrity

- buried and underground piping and tanks
- external surfaces monitoring of mechanical components
- flow-accelerated corrosion
- inspection of internal surfaces in miscellaneous piping and ducting components
- lube oil analysis
- one-time inspection
- open-cycle cooling water system
- TLAA
- water chemistry

LRA Tables 3.4.2-1 through 3.4.2-7 summarize AMRs for the steam and power conversion systems components and indicate AMRs claimed to be consistent with the GALL Report.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

LRA Table 3.4.1, item 3.4.1-11 addresses stainless steel or stainless-steel clad steel piping, piping components, piping elements, and tanks exposed to treated water greater than 60 °C (140 °F), which will be managed for cracking caused by SCC. LRA item 3.4.1-11 indicates that this aging effect is managed by the Water Chemistry and One-Time Inspection programs.

During its review of components associated with LRA item 3.4.1-11, for which the applicant cited generic note A, the staff noted that LRA Table 3.1.2-1 addresses stainless steel reactor coolant pressure boundary (RCPB) piping, piping components, and piping elements exposed to steam (internal). LRA Table 3.1.2-1 indicates that these components are related to LRA item 3.4.1-11 and cracking caused by SCC of these components are managed by the Water Chemistry and One-Time Inspection programs. In comparison, GALL Report item IV.C1.R-20 and SRP-LR Table 3.1-1, ID 97 address aging management for cracking caused by SCC of stainless steel piping, piping components, and piping elements greater than or equal to NPS 4 exposed to reactor coolant. The GALL Report and SRP-LR recommend GALL Report AMP XI.M2, "Water Chemistry," and GALL Report AMP XI.M7, "BWR Stress Corrosion Cracking" to manage the aging effect of the stainless steel components.

Therefore, the staff needed to clarify whether any of the applicant's stainless steel components addressed in LRA Table 3.1.2-1 is included in the scope of the BWR Stress Corrosion Cracking program or the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program, which performs periodic inspections. The staff also needed clarification as to the adequacy of the One-Time Inspection program that the applicant proposed to manage the aging effect.

By letter dated February 16, 2012, the staff issued RAI 3.4.1.11-1 requesting that the applicant clarify why any of these stainless steel components exposed to steam are not included in the scope of the BWR Stress Corrosion Cracking program or the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program. The staff also requested that the applicant justify why the One-Time Inspection program, which does not include periodic inspections, is adequate to manage cracking caused by SCC of these stainless steel components. In addition, the staff requested that the applicant clarify whether SCC has been observed in these components in order to demonstrate that the plant-specific operating experience supports the adequacy of the One-Time Inspection program to manage the aging effect.

In its response dated March 13, 2012, the applicant stated that the reactor core isolation cooling (RCIC) steam supply flow elements are the only stainless steel piping, piping components, and piping elements exposed internally to steam within the RCPB, which are addressed in LRA Table 3.1.2-1. The applicant also stated that these stainless steel flow elements are welded into the 4-inch carbon steel portion of the ASME Code Class 1 RCIC steam supply piping. The applicant further stated that the piping-to-flow-element welds are currently within the scope of the components managed by the BWR Stress Corrosion Cracking program, which is an augmented program within the ASME Code Section XI Inservice Inspection, Subsections IWB, IWC, and IWD program.

In addition, the applicant confirmed that based on its response to RAI 3.4.1.11-1, the One-Time Inspection program is not used to manage cracking caused by SCC of these stainless steel components, and the BWR Stress Corrosion Cracking program provides for periodic inspections to manage the aging effect of these components. The applicant also clarified that LRA item 3.1.1-97 is used to manage cracking of the RCIC stainless steel steam supply flow elements. The applicant provided the revisions to LRA Table 3.1.2-1, consistent with its response. The staff finds the applicant's response acceptable because the applicant confirmed that the BWR Stress Corrosion Cracking program is used to manage cracking caused by SCC of the stainless steel RCPB piping components, consistent with the GALL Report.

The staff's evaluations of the Water Chemistry, One-Time Inspection and the BWR Stress Corrosion Cracking programs are documented in SER Sections 3.0.3.1.2, 3.0.3.1.12, and 3.0.3.1.6, respectively. In its review of the non-RCPB components associated with LRA item 3.4.1-11, the staff finds the applicant's proposal to manage aging, using the Water Chemistry and One-Time Inspection programs, acceptable because the Water Chemistry program limits the concentrations of chemical species known to cause SCC and controls the dissolved oxygen level to minimize the environmental effect on SCC, and the One-Time Inspection program includes a one-time inspection of selected components to confirm the effectiveness of the Water Chemistry program. In its review of the RCPB components associated with LRA item 3.1.1-97, the staff finds the applicant's proposal to manage aging using the Water Chemistry and BWR Stress Corrosion Cracking programs acceptable because the Water Chemistry program controls and minimizes the environmental effect on SCC as described above, and the BWR Stress Corrosion Cracking program includes periodic volumetric inspections that can adequately detect and manage SCC of these components.

The staff concludes that for LRA items 3.4.1-11 and 3.1.1-97, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

LRA Table 3.4.2-7 addresses stainless steel electro-hydraulic control (EHC) drain tanks exposed internally to an environment of wetted air or gas and lubricating oil, which will be managed for loss of material. This component cites LRA items 3.4.1-39 and 3.4.1-44 and generic notes C and A, respectively, and credits the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Lubricating Oil Analysis and One-Time Inspection programs to manage this aging effect. During its review, the staff was not able to verify the material of construction for the EHC drain tank. By letter dated January 17, 2012, the staff issued RAI 3.4.2.7-1 requesting that the applicant verify the materials used for the fabrication of the EHC drain tank, and if necessary, provide the results of an updated aging management review, in accordance with 10 CFR 54.21(a)(1).

In its response dated February 15, 2012, the applicant stated that the EHC drain tank is an in-line piping component that is manufactured from stainless steel. The applicant also stated that the manufacturer of the component has provided information confirming that the EHC drain tank is fabricated from two stainless steel materials: Type 347 (columbium stabilized chromium nickel steel) and Type 309S stainless steel. The applicant further stated that these materials are consistent with the stainless steel material selection for the aging management review identified in LRA Table 3.4.2-7, and, therefore, no update to the aging management review is required.

Based on its review, the staff finds the applicant's response to RAI 3.4.2.7-1 acceptable because the applicant was able to confirm that the EHC drain tank was fabricated from stainless steel alloys; therefore, the staff's concern described in RAI 3.4.2.7-1 is resolved. The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Lubricating Oil Analysis, and One-Time Inspection programs are documented in SER Section 3.0.3.1.16, 3.0.3.1.17, and 3.0.3.1.12, respectively. In its review of this component associated with LRA item 3.4.1-39 and 3.4.1-44, the staff finds the applicant's proposal to manage aging, using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components, Lubricating Oil Analysis, and One-Time Inspection programs, acceptable because the visual inspections conducted by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components and One-Time Inspection programs are capable of detecting loss of material and between the two programs, both a one-time inspection will occur before the period of extended operation and opportunistic inspections will occur during the period of extended operation. Also, the Lubricating Oil Analysis program's preventive actions ensure that the quality of oil is sufficient to minimize the potential for loss of material to occur.

The staff concludes that for the stainless steel EHC drain tank, which cites LRA Items 3.4.1-39 and 3.4.1-44, the applicant has demonstrated that the effects of aging for these components will be adequately managed so that the intended functions(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.4.1 items 3.4.1-6, 3.4.1-22 through 3.4.1-29, 3.4.1-31, 3.4.1.32, 3.4.1.33, 3.4.1.35, 3.4.1-43, 3.4.1-48, 3.4.1-49, 3.4.1-51, 3.4.1-56, and 3.4.1-57, the applicant claimed that they were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable for these items.

For LRA Table 3.4.1 items 3.4.1-4, 3.4.1-13, 3.4.1-17, 3.4.1-36, 3.4.1-41, 3.4.1-42, 3.4.1-45, 3.4.1-46, and 3.4.1-53, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to PWRs. The staff reviewed the SRP-LR, confirmed these items only apply to PWRs, and finds these items are not applicable to LGS.

LRA Table 3.4.1, item 3.4.1-7 addresses high-strength steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage cracking caused by cyclic loading and SCC for this component group. The applicant stated that this item is not applicable because there is no steel high-strength bolting exposed to air with steam or water leakage in the steam and power conversion systems. The staff evaluated the applicant's claim and found it acceptable because a search of the UFSAR did not reveal any details on high-strength bolting, and given the lack of specificity in Chapter 10 of the UFSAR in relation to bolting materials, the staff reviewed the seven most recent BWR LRAs (i.e., Grand Gulf, Hope Creek, Columbia, Vermont Yankee, Pilgrim, Duane Arnold Energy Center, Cooper) for item 3.4.1-7 (Revision 2) and 3.4.1-21 (Revision 1), all of which identified the item as not applicable.

LRA Table 3.4.1, item 3.4.1-9, addresses steel closure bolting exposed to air with steam or water leakage. The GALL Report recommends GALL Report AMP XI.M18, "Bolting Integrity," to manage loss of material caused by general corrosion for this component group. The applicant stated that this item is not applicable because there is no steel closure bolting exposed to air with steam or water leakage in the steam and power conversion systems. The staff evaluated the applicant's claim and found it acceptable because all steam and power conversion system bolting exposed to air is being managed for loss of material by the Bolting Integrity program using item 3.4.1-08. This program conducts periodic visual inspections capable of detecting loss of material caused by general corrosion in bolting, and use of this program is consistent with the GALL Report.

LRA Table 3.4.1, item 3.4.1-20, addresses copper-alloy and stainless steel piping components exposed to raw water. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to manage loss of material caused by pitting, crevice, and MIC for this component group. The applicant stated that this item is not applicable because there are no copper-alloy piping components exposed to raw water in the steam and power conversion systems, and that the stainless steel piping components in these systems are being addressed through LRA item 3.4.1-21. The staff noted that LRA item 3.4.1-21 is similar to item 3.4.1-20, but also manages for the additional aging effect of fouling that leads to corrosion. The staff evaluated the applicant's claim and found it acceptable because the staff confirmed that there are no copper-alloy piping components exposed to raw water in the steam and power conversion systems and that stainless steel piping components exposed to raw water in the steam and power conversion systems reference LRA item 3.4.1-21, which manages for loss of material in a manner consistent with LRA Table 3.4.1, item 3.4.1-20, and the GALL Report recommendations.

LRA Table 3.4.1, item 3.4.1-38, addresses steel piping, piping components, and piping elements exposed to raw water. The GALL Report recommends GALL Report AMP XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components," to manage loss of material caused by general, pitting, crevice, galvanic, and MIC, and fouling that leads to corrosion, for this component group. The applicant stated that this item is not applicable because it is applicable to PWRs only. The staff evaluated the applicant's claim and found it acceptable because, although the LRA contains this material-environment-aging effect combination, the applicant chose to reference LRA item 3.4.1-19, which manages aging in a manner consistent with other GALL Report recommendations for steel piping exposed to raw water (e.g., the GALL Report item V.C.E-22). The staff noted that LRA item 3.4.1-19 uses the Open-Cycle Cooling Water System program to manage for loss of material caused by general, pitting, crevice, galvanic, and MIC, and fouling that leads to corrosion. The staff also noted that the visual examinations, nondestructive evaluations, and water chemistry treatments in the Open-Cycle Cooling Water System program are capable of mitigating and detecting loss of material and fouling before loss of intended function(s).

LRA Table 3.4.1, item 3.4.1-50, addresses steel bolting exposed to soil. The GALL Report recommends AMP XI.M41 "Buried and Underground Piping and Tanks" to manage loss of material caused by general, pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because there is no steel bolting exposed to soil in the steam and power conversion systems. The staff evaluated the applicant's claim and found it acceptable because based on a review of LRA Section 3.4 and, during the audit, site drawings, the staff confirmed that there are no flanged joints, and therefore, no steel bolting in the portion of the circulating water system within the scope of license renewal.

LRA Table 3.4.1, item 3.4.1-50x, addresses stainless steel and steel piping, piping components, and piping elements exposed to an underground environment. The GALL Report recommends AMP XI.M41 "Buried and Underground Piping and Tanks" program to manage loss of material caused by general (steel only), pitting and crevice corrosion for this component group. The applicant stated that this item is not applicable because it will use item 3.4.1-47 to manage the aging of these components. The staff evaluated the applicant's claim and found it acceptable because although 3.4.1-47 is for a soil or concrete environment, both items manage the same aging effects and use the same program to manage the aging.

3.4.2.1.2 Loss of Material Caused by Pitting, Crevice, And Microbiologically-Influenced Corrosion; Fouling that Leads to Corrosion

LRA Table 3.4.1, item 3.4.1-21, addresses stainless steel heat exchanger components exposed to raw water, which will be managed for loss of material caused by pitting, crevice, and MIC and fouling that leads to corrosion. For the AMR items that cite generic note E, the LRA credits the Bolting Integrity program to manage loss of material for stainless steel bolting exposed to raw water in the certain components in the circulating water system. The GALL Report recommends GALL Report AMP XI.M20, "Open-Cycle Cooling Water System," to ensure these aging effects are adequately managed.

The staff noted that the items are associated with the cooling tower basin removable screens, and that the Bolting Integrity program proposes to manage loss of material by performing periodic visual inspections. The staff's evaluation of the Bolting Integrity program is documented in SER Section 3.0.3.2.3. In its review of components associated with item 3.4.1-21, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the above program acceptable because the Bolting Integrity program performs periodic inspections to identify loss of material for bolts and it is the appropriate AMP to manage aging of stainless steel bolting in raw water environments.

The staff concludes that for LRA item 3.4.1-21, 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.1.3 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed were not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed were not applicable are not applicable to LGS Units 1 and 2.

As discussed in SER Section 3.0.2.2, for those AMRs that the applicant claimed consistency with the GALL Report, the staff evaluated the applicant's claim of consistency. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent.

Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.4.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.4.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the steam and power conversion systems components and provides information concerning how it will manage the following aging effects:

- cumulative fatigue damage
- cracking caused by SCC
- loss of material caused by pitting and crevice corrosion
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.4.2.2. The staff's review of the applicant's further evaluation follows.

3.4.2.2.1 Cumulative Fatigue Damage

LRA Section 3.4.2.2.1, which is associated with LRA Table 3.4.1 item 3.4.1-1, addresses steel piping, piping components, and piping elements exposed to steam or treated water in the steam and power conversion system and are being managed for cumulative fatigue damage. The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA, as defined in 10 CFR 54.3, and is required to be evaluated in accordance with 10 CFR 54.21(c). The applicant stated that the TLAA identified for the steam and power conversion systems is addressed separately in LRA Section 4.3.

The staff reviewed LRA Section 3.4.2.2.1 against the criteria in SRP-LR Section 3.4.2.2.1 which states that fatigue of steam and power conversion system components is a TLAA as defined in 10 CFR 54.3, and that these TLAAs are to be evaluated in accordance with 10 CFR 54.21(c)(1) and SRP-LR Section 4.3. The staff also reviewed the AMRs items associated with LRA Section 3.4.2.2.1, and found that the AMR results are consistent with the GALL Report and SRP-LR.

Based on its review, the staff concludes that the applicant has met the SRP-LR Section 3.4.2.2.1 criteria. For those items that apply to LRA Section 3.4.2.2.1, the staff determined that the LRA is consistent with the GALL Report and that the applicant has demonstrated that it will adequately manage the effects of aging so that the intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3). SER Section 4.3 documents the staff's review of the applicant's evaluation of the TLAA for these components.

3.4.2.2.2 Cracking Caused by Stress Corrosion Cracking

LRA Section 3.4.2.2.2, associated with LRA Table 3.4.1, item 3.4.1-2 addresses stainless steel piping, piping components, piping elements and tanks exposed to outdoor air. The criteria in the SRP-LR states that either the applicant justifies that the aging effect is not applicable by describing the outdoor air environment present at the plant and demonstrating that stress corrosion cracking is not expected, or GALL Report AMP XI.M36, "External Surfaces Monitoring of Mechanical Components," is used to manage cracking caused by SCC for this component group. The applicant addressed the further evaluation criteria of the SRP-LR by stating that, "SCC of stainless steels exposed to outdoor air and contaminants is considered plausible only if the material temperature is above 140 °F. For the Steam and Power Conversion systems, the outdoor stainless steel components are less than 140 °F."

In its review of components associated with item 3.3.1-4, the staff noted that the environment is periodically subject to wetting (e.g., condensation, rain) which could introduce halides (e.g., cooling tower drift), which are known to contribute to SCC. LRA Section 2.4.7 further states that two circulating water chlorine and acid feed enclosures are used to maintain the chemical properties of the cooling tower basins, which can also contribute to halides in condensation. By letter dated January 17, 2012, the staff issued RAI B.2.1.25-1, requesting that the applicant provide technical justification as to why the LRA AMP does not consider SCC to be an aging effect requiring management for the stainless steel components in the auxiliary systems that are subjected to wet external environments.

In its response dated February 15, 2012, the applicant stated that although chlorine, as sodium hypochlorite, is added to the water in the cooling towers, prevailing wind direction is such that the cooling tower plume is directed away from the plant, a review of plant operating experience has revealed no occurrences of cracking in outdoor stainless steel components, and recent inspections performed on the external surfaces of large outdoor stainless steel components have revealed that these components are in good material condition (recent inspections reveal no occurrences of cracking). The applicant revised its response to the further evaluation criteria of the SRP-LR by stating that this item is not applicable because LGS is located more than 80 miles from the Atlantic coast and major transportation routes near the site are at least a mile away.

The staff does not find the response to RAI B.2.1.25-1 to be acceptable because experimental studies and industry operating experience in chloride-containing (coastal) environments have shown that stainless steels exposed to an outdoor air environment can crack at temperatures as low as 104 to 120 °F, depending on humidity, component surface temperature, and contaminant concentration and composition. The staff noted that while the experimental studies demonstrated that cracking can occur in 4 to 52 weeks, the industry operating experience failures did not necessarily occur early in plant life; therefore, the staff cannot conclude that recent inspections are sufficient to demonstrate an aging effect will not occur during the period of extended operation. By letter dated June 12, 2012, the staff issued RAI B.2.1.25-1.1 requesting that the applicant state the basis for why the chemical compounds in the cooling tower plume cannot result in SCC if plume fallout (regardless of prevailing wind direction) accumulates on the external surfaces of stainless steel piping within the scope of license renewal and why chloride contamination is not expected to accumulate on stainless steel components within the scope of license renewal from the soil or nearby agricultural and industrial sources.

In its response dated June 19, 2012, the applicant stated that SCC is not likely to occur because local temperatures have not exceeded 104 °F and only exceeded 100 °F on two days in the last 10 years. In addition, the applicant stated that they were not in a coastal environment. The applicant did not respond to the potential for chloride contamination arising from agricultural or industrial sources; however, it revised the External Surfaces Monitoring of Mechanical Components program to manage stainless steel components in an outdoor air environment for SCC. The applicant stated that components that are jacketed or located in underground vaults would not be managed for SCC because they are shielded from accumulation of contaminants in the atmosphere. The applicant revised LRA Sections A.2.1.25, B.2.1.25, 3.4.2.1.1, 3.4.2.2.2, and LRA Tables 3.4.1 (item 3.4.1-2), 3.4.2-1 and 3.4.2-2 accordingly.

The staff finds the applicant's response to RAI B.2.1.25-1.1 acceptable because the applicant will manage SCC of stainless steel components exposed to outdoor air using the External Surfaces Monitoring of Mechanical Components program, components that are jacketed or in underground vaults would not be exposed to sufficient quantities of atmospheric chlorides to cause SCC because they are protected from direct fallout by the intervening materials, the visual inspections of this program are capable of detecting SCC, and managing the aging of these AMR items in this manner is consistent with the GALL Report.

3.4.2.2.3 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Section 3.4.2.2.3 associated with LRA Table 3.4.1 item 3.4.1-3, addresses stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air that will be managed for loss of material caused by pitting and crevice corrosion by the External Surfaces Monitoring of Mechanical Components program. The recommendations in SRP-LR Section 3.4.2.2.3 state that loss of material caused by pitting and crevice corrosion could occur for stainless steel piping, piping components, piping elements, and tanks exposed to outdoor air. The applicant addressed the further evaluation criteria of the SRP-LR by stating that any visible evidence of loss of material will be evaluated and entered into the CAP.

The staff's evaluation of the External Surfaces Monitoring of Mechanical Components program is documented in SER Section 3.0.3.1.15. The staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the External Surfaces Monitoring of Mechanical Components program is acceptable because the AMP provides for management of aging effects through periodic visual inspection of external surfaces for evidence of loss of material.

3.4.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.4.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.4.2-1 through 3.4.2-7, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Tables 3.4.2-1 through 3.4.2-7, the applicant, by notes F through J, indicated that the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether 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. The staff's evaluation is documented in the following sections.

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

The staff reviewed LRA Table 3.4.2-1, which summarizes the results of AMR evaluations for the circulating water system component groups.

In LRA Table 3.4.2-1, the applicant stated that there is no aging effect for polymeric strainer elements exposed externally to outdoor air and raw water and no AMP is proposed. The AMR items cite generic note G. These items cite plant-specific note 3, which states that the component is constructed of fiber-reinforced plastic.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable for the internal raw water environment based on its review of *The Corrosion Resistant Materials Handbook*, by D. J. De Renzo and Ibert Mellan, 4th Edition, which states that fiberglass reinforced pipe is acceptable for use in raw water environments up to 200 °F, which is higher than the design rating of the circulating water system. The staff lacks sufficient information to conclude that no aging management is required for exposure to the outdoor air environment because the type of fiber reinforced material (e.g., epoxy resin, reinforced vinyl ester resin) could influence the impact of exposure to outdoor ultraviolet (UV) light. By letter dated January 18, 2012, the staff issued RAI 3.4.2.3.1-1 requesting the applicant to state the specific specification/grade of fiber-reinforced material used in the polymeric strainer element components within the scope of license renewal and the basis for why exposure to outdoor UV does not require age managing of these components.

In its response, dated February 16, 2012, the applicant stated that the material used for the strainer element is not known and upon further review, the strainer elements made of fiber-reinforced polymeric material have been determined to be submerged during normal cooling tower operation and are covered by at least 2 feet of water; therefore, the external outdoor air environment for the strainer element as identified in LRA Table 3.4.2-1 is not applicable. The applicant also revised LRA Table 3.4.2-1 to reflect the deletion of the outdoor air environment.

The staff finds the applicant's response acceptable because the component is underwater and, therefore, not significantly exposed to outdoor UV. The staff's concern described in RAI 3.4.2.3.1-1 is resolved.

By letter dated February 15, 2012, LRA Tables 3.4.2-1 and 3.4.2-2 added stainless steel strainer (element) and valve body exposed externally to outdoor air, and no AERM or AMP is proposed. The AMR items cite generic note I. Items associated with Table 3.4.2-1 and 3.4.2-2 cite plant-specific notes 4 and 1, which state that based on plant-specific environmental condition and operating experience, cracking is not an applicable aging effect since outdoor environments are not conducive to SCC.

The staff reviewed the associated items in the LRA to confirm that this aging effect(s) is not applicable for this component, material, and environment combination. The staff evaluation is documented in SER Section 3.4.2.2.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.4.2.4.2 Condensate System – Summary of Aging Management Review – LRA Table 3.3.2-2

The staff reviewed LRA Table 3.3.2-2, which summarizes the results of AMR evaluations for the condensate component groups.

By letter dated February 15, 2012, LRA Tables 3.4.2-1 and 3.4.2-2 added stainless steel strainer (element) and valve body exposed externally to outdoor air, and no AERM or AMP is proposed. The staff's evaluation of these items is documented in 3.3.2.3.3.

In LRA Table 3.4.2-2, the applicant stated that for valve bodies exposed externally to outdoor air no AERM or AMP is proposed. The AMR item cites generic note I and plant-specific note 1, which states that these components are jacketed and not directly exposed to the outdoor air environment and, therefore, not susceptible to SCC.

The staff reviewed the associated items in the LRA to confirm that this aging effect is not applicable for this component, material, and environment combination. The staff's evaluation is documented in SER Section 3.4.2.2.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.4.2.4.3 Condenser and Air Removal System – Summary of Aging Management Review – LRA Table 3.4.2-3

The staff reviewed LRA Table 3.4.2-3, which summarizes the results of AMR evaluations for the condenser and air removal system component groups.

In LRA Table 3.4.2-3, the applicant stated that carbon steel heat exchanger components exposed internally to treated water will be managed for loss of material by the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program. The AMR item cites generic note H.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report, which states that steel heat exchanger components exposed to treated water are subject to a loss of material aging effect, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program is documented in SER Section 3.0.3.1.16. The staff finds the applicant's proposal to manage aging using the Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components program acceptable because the program uses visual inspections during periodic surveillances, maintenance activities, and during scheduled outages, which is an adequate technique for identify this aging effect.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.4.2.4.4 Extraction Steam System - Summary of Aging Management Review – LRA Table 3.3.2-4

The staff reviewed LRA Table 3.3.2-4, which summarizes the results of AMR evaluations for the extraction steam component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.4.2.4.5 Feedwater System – Summary of Aging Management Review – LRA Table 3.3.2-5

The staff reviewed LRA Table 3.3.2-5, which summarizes the results of AMR evaluations for feedwater system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.4.2.4.6 Main Steam System – Summary of Aging Management Review – LRA Table 3.3.2-6

The staff reviewed LRA Table 3.3.2-6, which summarizes the results of AMR evaluations for main steam system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.4.2.4.7 Main Turbine System – Summary of Aging Management Review – LRA Table 3.3.2-7

The staff reviewed LRA Table 3.3.2-7, which summarizes the results of AMR evaluations for feedwater system component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.4.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the steam and power conversion system components within the scope of license renewal and subject to an AMR will be adequately managed so that the intended functions will remain consistent with the CLB for the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5 Aging Management of Structures and Component Supports

This SER Section documents the staff's review of the applicant's AMR results for the structures and component supports groups of:

- 220 and 500 kV substations
- admin building shop and warehouse
- auxiliary boiler and lube oil storage enclosure
- circulating water pump house
- component supports commodities group
- control enclosure
- cooling towers
- diesel oil storage tank structures
- EDG enclosure
- piping and component insulation commodity group
- primary containment
- radwaste enclosure
- reactor enclosure
- SW pipe tunnel
- spray pond and pump house

- turbine enclosure
- yard facilities

3.5.1 Summary of Technical Information in the Application

LRA Section 3.5 provides AMR results for the structures and component supports components and component groups. LRA Table 3.5.1, "Summary of Aging Management Programs for Structures and Component Supports Evaluated in Chapters II and III of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the structures and component supports components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.5.2 Staff Evaluation

The staff reviewed LRA Section 3.5 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the structures and component supports components within the scope of license renewal and subject to an AMR, 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 conducted a review of AMRs to ensure the applicant's claim that certain AMRs are consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3.

During its review, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations are consistent with the SRP-LR Section 3.5.2.2 acceptance criteria. The staff's evaluations are documented in SER Section 3.5.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.5.2.3.

For SSCs the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to verify the applicant's claims.

Table 3.5-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.5 and addressed in the GALL Report.

Table 3.5-1 Staff Evaluation for Structures and Component Supports Components in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
BWR Concrete and Steel (Mark I, II, and III) Containments					
Concrete: dome; wall; basemat; ring girders; buttresses, concrete elements, all (3.5.1-1)	Cracking and distortion caused by increased stress levels from settlement	Chapter XI.S2, "ASME Code Section XI, Subsection IWL" or Chapter XI.S6, "Structure Monitoring" If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if a de-watering system is relied upon to control settlement	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.1)
Concrete: foundation; subfoundation (3.5.1-2)	Reduction of foundation strength and cracking caused by differential settlement and erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring" If a de-watering system is relied upon for control of erosion, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes, if a de-watering system is relied upon to control settlement	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.1)
Concrete: dome; wall; basemat; ring girders; buttresses; concrete: containment; wall; basemat; concrete: basemat, concrete fill-in annulus (3.5.1-3)	Reduction of strength and modulus caused by elevated temperature (>150 °F general; >200 °F local)	A plant-specific aging management program is to be evaluated.	Yes, if temperature limits are exceeded	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.2)
Steel elements (inaccessible areas): drywell shell; drywell head; and drywell shell (3.5.1-4)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes, if corrosion is indicated from the IWE examinations	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.3(1))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements (inaccessible areas): liner; liner anchors; integral attachments; steel elements (inaccessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable) (3.5.1-5)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE" and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes, if corrosion is indicated from the IWE examinations	ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with GALL Report (see SER Section 3.5.2.2.1.3(1))
Steel elements: torus shell (3.5.1-6)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE" and Chapter XI.S4, "10 CFR Part 50, Appendix J"	Yes, if corrosion is significant. Recoating of the torus is recommended	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.3(2))
Steel elements: torus ring girders; downcomers; steel elements: suppression chamber shell (interior surface) (3.5.1-7)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE"	Yes, if corrosion is significant	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.3(3))
Pre-stressing system: tendons (3.5.1-8)	Loss of prestress caused by relaxation; shrinkage; creep; elevated temperature	Yes, TLAA	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.4)
Penetration sleeves; penetration bellows steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell; unbraced downcomers, steel elements: vent header; downcomers (3.5.1-9)	Cumulative fatigue damage caused by fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.5.2.2.1.5)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Penetration sleeves; penetration bellows (3.5.1-10)	Cracking caused by stress corrosion cracking	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.6)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): basemat, concrete (inaccessible areas): dome; wall; basemat (3.5.1-11)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Further evaluation is needed for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557).	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.7)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): basemat, concrete (inaccessible areas): containment; wall; basemat, concrete (inaccessible areas): basemat, concrete fill-in annulus (3.5.1-12)	Cracking caused by expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.8)
Concrete (inaccessible areas): basemat, concrete (inaccessible areas): dome; wall; basemat (3.5.1-13)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.9)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): containment; wall; basemat (3.5.1-14)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.1.9)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (accessible areas): basemat (3.5.1-15)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Concrete (accessible areas): basemat, concrete: containment; wall; basemat (3.5.1-16)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S2, "ASME Code Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses (3.5.1-17)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): basemat (3.5.1-18)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): basemat, concrete (accessible areas): containment; wall; basemat, concrete (accessible areas): basemat, concrete fill-in annulus (3.5.1-19)	Cracking caused by expansion from reaction with aggregates	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses, concrete (accessible areas): containment; wall; basemat (3.5.1-20)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Concrete (accessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel, concrete (accessible areas): basemat; reinforcing steel, concrete (accessible areas): dome; wall; basemat; reinforcing steel (3.5.1-21)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	ASME Code Section XI, Subsection IWL	Consistent with the GALL Report
Concrete (inaccessible areas): basemat; reinforcing steel (3.5.1-22)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Concrete (inaccessible areas): basemat; reinforcing steel, concrete (inaccessible areas): dome; wall; basemat; reinforcing steel (3.5.1-23)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S2, "ASME Code Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses, concrete (inaccessible areas): basemat, concrete (accessible areas): dome; wall; basemat (3.5.1-24)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S2, "ASME Code Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Concrete (inaccessible areas): dome; wall; basemat; ring girders; buttresses; reinforcing steel (3.5.1-25)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S2, "ASME Code Section XI, Subsection IWL," or Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to BWRs (see SER Section 3.5.2.1.1)
Moisture barriers (caulking, flashing, and other sealants) (3.5.1-26)	Loss of sealing caused by wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S1, "ASME Code Section XI, Subsection IWE"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Penetration sleeves; penetration bellows, Steel elements: torus; vent line; vent header; vent line bellows; downcomers, suppression pool shell (3.5.1-27)	Cracking caused by cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Personnel airlock, equipment hatch, CRD hatch (3.5.1-28)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Personnel airlock, equipment hatch, CRD hatch: locks, hinges, and closure mechanisms (3.5.1-29)	Loss of leak tightness caused by mechanical wear of locks, hinges and closure mechanisms	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Pressure-retaining bolting (3.5.1-30)	Loss of preload caused by self-loosening	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Pressure-retaining bolting, steel elements: downcomer pipes (3.5.1-31)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE"	No	ASME Code Section XI, Subsection IWE	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Prestressing system: tendons; anchorage components (3.5.1-32)	Loss of material caused by corrosion	Chapter XI.S2, "ASME Code Section XI, Subsection IWL"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Seals and gaskets (3.5.1-33)	Loss of sealing caused by wear, damage, erosion, tear, surface cracks, or other defects	Chapter XI.S4, "10 CFR Part 50, Appendix J "	No	10 CFR Part 50 Appendix J	Consistent with the GALL Report
Service Level I coatings (3.5.1-34)	Loss of coating integrity caused by blistering, cracking, flaking, peeling, or physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	Protective Coating Monitoring and Maintenance	Consistent with the GALL Report
Steel elements (accessible areas): liner; liner anchors; integral attachments, penetration sleeves, steel elements (accessible areas): drywell shell; drywell head; drywell shell in sand pocket regions; steel elements (accessible areas): suppression chamber; drywell; drywell head; embedded shell; region shielded by diaphragm floor (as applicable), steel elements (accessible areas): drywell shell; drywell head (3.5.1-35)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report
Steel elements: drywell head; downcomers (3.5.1-36)	Fretting or lockup caused by mechanical wear	Chapter XI.S1, "ASME Code Section XI, Subsection IWE"	No	ASME Code Section XI, Subsection IWE	Consistent with the GALL Report
Steel elements: suppression chamber (torus) liner (interior surface) (3.5.1-37)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel elements: suppression chamber shell (interior surface) (3.5.1-38)	Cracking caused by stress corrosion cracking	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Steel elements: vent line bellows (3.5.1-39)	Cracking caused by stress corrosion cracking	Chapter XI.S1, "ASME Code Section XI, Subsection IWE," and Chapter XI.S4, "10 CFR Part 50, Appendix J"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Unbraced downcomers, steel elements: vent header; downcomers (3.5.1-40)	Cracking caused by cyclic loading (CLB fatigue analysis does not exist)	Chapter XI.S1, "ASME Code Section XI, Subsection IWE"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Steel elements: drywell support skirt, steel elements (inaccessible areas): support skirt (3.5.1-41)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report
Safety-Related and Other Structures; and Component Supports					
Groups 1-3, 5, 7-9:concrete (inaccessible areas): foundation (3.5.1-42)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557)	Yes	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1(1))
All groups except group 6:concrete (inaccessible areas): all (3.5.1-43)	Cracking caused by expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.2.1(2))
All groups: concrete: all (3.5.1-44)	Cracking and distortion caused by increased stress levels from settlement	Chapter XI.S6, "Structures Monitoring" If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1(3))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-45)	Reduction in foundation strength, cracking caused by differential settlement, erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring" If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.2.1(3))
Groups 1-3, 5-9: concrete: foundation; subfoundation (3.5.1-46)	Reduction of foundation strength and cracking caused by differential settlement and erosion of porous concrete subfoundation	Chapter XI.S6, "Structures Monitoring" If a de-watering system is relied upon for control of settlement, then the licensee is to ensure proper functioning of the de-watering system through the period of extended operation.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.2.1(3))
Groups 1-5, 7-9: concrete (inaccessible areas): exterior above- and below-grade; foundation (3.5.1-47)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes,	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.2.2.1(4))
Groups 1-5: concrete: all (3.5.1-48)	Reduction of strength and modulus caused by elevated temperature (>150 °F general; >200 °F local)	A plant-specific aging management program is to be evaluated.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.2.2)
Group 6 – concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-49)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index >100 day-inch/yr) (NUREG-1557)	Yes	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report (see SER Section 3.5.2.2.2.3(1))
Group 6: concrete (inaccessible areas): all (3.5.1-50)	Cracking caused by expansion from reaction with aggregates	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	NA	Consistent with the GALL Report (see SER Section 3.5.2.2.2.3(2))

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: concrete (inaccessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-51)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Further evaluation is required to determine if a plant-specific aging management program is needed.	Yes	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report (see SER Section 3.5.2.2.2.3(3))
Groups 7, 8 - steel components: tank liner (3.5.1-52)	Cracking caused by stress corrosion cracking; Loss of material caused by pitting and crevice corrosion	A plant-specific aging management program is to be evaluated.	Yes	NA	Not applicable to LGS (see SER Section 3.5.2.2.2.4)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-53)	Cumulative fatigue damage caused by fatigue (Only if CLB fatigue analysis exists)	Yes, TLAA	Yes,	NA	Not applicable to LGS (See SER subsection 3.5.2.2.2.5)
All groups except 6: concrete (accessible areas): all (3.5.1-54)	Cracking caused by expansion from reaction with aggregates	Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Building concrete at locations of expansion and grouted anchors; grout pads for support base plates (3.5.1-55)	Reduction in concrete anchor capacity caused by local concrete degradation/ service-induced cracking or other concrete aging mechanisms	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Concrete: exterior above- and below-grade; foundation; interior slab (3.5.1-56)	Loss of material caused by abrasion; cavitation	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants and Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.1.2)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Constant and variable load spring hangers; guides; stops (3.5.1-57)	Loss of mechanical function caused by corrosion, distortion, dirt, overload, fatigue caused by vibratory and cyclic thermal loads	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Earthen water-control structures: dams; embankments; reservoirs; channels; canals and ponds (3.5.1-58)	Loss of material; loss of form caused by erosion, settlement, sedimentation, frost action, waves, currents, surface runoff, seepage	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Group 6: concrete (accessible areas): all (3.5.1-59)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Group 6: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-60)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Group 6: concrete (accessible areas): exterior above- and below-grade; foundation; interior slab (3.5.1-61)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Group 6: Wooden Piles; sheeting (3.5.1-62)	Loss of material; change in material properties caused by weathering, chemical degradation, and insect infestation repeated wetting and drying, fungal decay	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-63)	Increase in porosity and permeability; loss of strength caused by leaching of calcium hydroxide and carbonation	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring Program	Consistent with the GALL Report
Groups 1-3, 5, 7-9: concrete (accessible areas): exterior above- and below-grade; foundation (3.5.1-64)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring Program	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Groups 1-3, 5, 7-9: concrete (accessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all (3.5.1-65)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Groups 1-5, 7, 9: concrete (accessible areas): interior and above-grade exterior (3.5.1-66)	Cracking; loss of bond; and loss of material (spalling, scaling) caused by corrosion of embedded steel	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Groups 1-5, 7, 9: Concrete: interior; above-grade exterior, Groups 1-3, 5, 7-9: concrete (inaccessible areas): below-grade exterior; foundation, Group 6: concrete (inaccessible areas): all (3.5.1-67)	Increase in porosity and permeability; cracking; loss of material (spalling, scaling) caused by aggressive chemical attack	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
High-strength structural bolting (3.5.1-68)	Cracking caused by stress corrosion cracking	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
High-strength structural bolting (3.5.1-69)	Cracking caused by stress corrosion cracking	Chapter XI.S6, "Structures Monitoring" Note: ASTM A 325, F 1852, and ASTM A 490 bolts used in civil structures have not shown to be prone to SCC. SCC potential need not be evaluated for these bolts.	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Masonry walls: all (3.5.1-70)	Cracking caused by restraint shrinkage, creep, and aggressive environment	Chapter XI.S5, "Masonry Walls"	No	Masonry Walls	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Masonry walls: all (3.5.1-71)	Loss of material (spalling, scaling) and cracking caused by freeze-thaw	Chapter XI.S5, "Masonry Walls"	No	Masonry Walls	Consistent with the GALL Report
Seals; gasket; moisture barriers (caulking, flashing, and other sealants) (3.5.1-72)	Loss of sealing caused by deterioration of seals, gaskets, and moisture barriers (caulking, flashing, and other sealants)	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Service Level I coatings (3.5.1-73)	Loss of coating integrity caused by blistering, cracking, flaking, peeling, physical damage	Chapter XI.S8, "Protective Coating Monitoring and Maintenance"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Sliding support bearings; sliding support surfaces (3.5.1-74)	Loss of mechanical function caused by corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Sliding surfaces (3.5.1-75)	Loss of mechanical function caused by corrosion, distortion, dirt, debris, overload, wear	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Sliding surfaces: radial beam seats in BWR drywell (3.5.1-76)	Loss of mechanical function caused by corrosion, distortion, dirt, overload, wear	Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Steel components: all structural steel (3.5.1-77)	Loss of material caused by corrosion	Chapter XI.S6, "Structures Monitoring" If protective coatings are relied upon to manage the effects of aging, the structures monitoring program is to include provisions to address protective coating monitoring and maintenance.	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Steel components: fuel pool liner (3.5.1-78)	Cracking caused by stress corrosion cracking; Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Monitoring of the spent fuel pool water level in accordance with technical specifications and leakage from the leak chase channels.	No, unless leakages have been detected through the SFP liner that cannot be accounted for from the leak chase channels	Water Chemistry	Consistent with the GALL Report
Steel components: piles (3.5.1-79)	Loss of material caused by corrosion	Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)
Structural bolting (3.5.1-80)	Loss of material caused by general, pitting and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring and Inspection of Overhead Heavy and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.5.2.1.3)
Structural bolting (3.5.1-81)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Structural bolting (3.5.1-82)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Structural bolting (3.5.1-83)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants" or the FERC/US Army Corps of Engineers dam inspections and maintenance programs.	No	RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants	Consistent with the GALL Report
Structural bolting (3.5.1-84)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," and Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	NA	Not applicable to LGS (see SER Section 3.5.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Structural bolting (3.5.1-85)	Loss of material caused by pitting and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water, and Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	Water Chemistry, ASME Code Section XI, Subsection IWF, and Inspection of Overhead Heavy and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.5.2.1.4)
Structural bolting (3.5.1-86)	Loss of material caused by pitting and crevice corrosion	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Structural bolting (3.5.1-87)	Loss of preload caused by self-loosening	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Structural bolting (3.5.1-88)	Loss of preload caused by self-loosening	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring and Inspection of Overhead Heavy and Light Load (Related to Refueling) Handling Systems	Consistent with the GALL Report (see SER Section 3.5.2.1.3)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-89)	Loss of material caused by boric acid corrosion	Chapter XI.M10, "Boric Acid Corrosion"	No	NA	Not applicable to BWRs (see SER Section 3.5.2.1.1)
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-90)	Loss of material caused by general (steel only), pitting, and crevice corrosion	Chapter XI.M2, "Water Chemistry," for BWR water, and Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	Water Chemistry and ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-91)	Loss of material caused by general and pitting corrosion	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	ASME Code Section XI, Subsection IWF	Consistent with the GALL Report
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-92)	Loss of material caused by general and pitting corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Support members; welds; bolted connections; support anchorage to building structure (3.5.1-93)	Loss of material caused by pitting and crevice corrosion	Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring, RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants, and ASME Code Section XI, Subsection IWF	Consistent with the GALL Report (see SER Section 3.5.2.1.5)
Vibration isolation elements (3.5.1-94)	Reduction or loss of isolation function caused by radiation hardening, temperature, humidity, sustained vibratory loading	Chapter XI.S3, "ASME Code Section XI, Subsection IWF"	No	Structures Monitoring	Consistent with the GALL Report (see SER Section 3.5.2.1.6)
Aluminum, galvanized steel and stainless steel support members; welds; bolted connections; support anchorage to building structure exposed to air-indoor, uncontrolled (3.5.1-95)	None	None	NA – No AEM or AMP	NA	Consistent with the GALL Report

The staff's review of the structures and component supports component groups followed any one of several approaches. One approach, documented in SER Section 3.5.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.5.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.5.2.3, reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the structures and component supports components is documented in SER Section 3.0.3.

3.5.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.5.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the structures and structural components and their commodity groups:

- 10 CFR Part 50, Appendix J
- aboveground metallic tanks
- ASME Code Section XI, Subsection IWE
- ASME Code Section XI, Subsection IWF
- ASME Code Section XI, Subsection IWL
- masonry walls
- Protective Coating Monitoring and Maintenance program
- RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants"
- structures monitoring
- TLAA
- water chemistry

Although not identified directly in LRA Section 3.5.2.1, LRA Table 3.5.1 identifies the following additional program under the discussion column that manages aging effects for the structures and structural components and their commodity groups for specified conditions: Inspection of Overhead Heavy and Light Load (Related to Refueling) Handling Systems.

LRA Tables 3.5.2-1 through 3.5.2-17 summarize AMRs for the structures and component supports component groups and indicate AMRs claimed to be consistent with the GALL Report.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

LRA Table 3.5.1, item 3.5.1-78 addresses steel fuel pool liner components, which will be managed for cracking caused by stress corrosion cracking and loss of material caused by pitting and crevice corrosion with the Water Chemistry program and monitoring of the spent fuel pool water level. The staff noted that the applicant limited the applicable aging effect to loss of material and also monitors for changes in leakage in the leak chase channel drainage system. During its review of components associated with item 3.5.1-78 for which the applicant originally cited generic notes A or C, the staff noted that the applicant applied this item to components, such as debris screens, for which monitoring of the spent fuel pool water level and leak chase channel draining system may not be appropriate activities to verify the effectiveness of the Water Chemistry program. By letter dated January 16, 2012, the staff issued RAI 3.5.2.11-1 requesting that the applicant propose an alternative activity to verify the effectiveness of the Water Chemistry program for those items that reference LRA item 3.5.1-78, for which monitoring of the spent fuel pool water level and leak chase channel draining system would not be expected to detect degradation.

In its response dated March 13, 2012, the applicant removed the AMR items (all of the generic note C items and one of the generic note A items) for the stainless steel refueling bellows; debris screens, grating and bars; and the reactor well, dryer and separator pool, and cask loading pit liners; and integral attachments exposed to the treated water environment. The applicant stated that these items are only exposed to treated water during refueling outages, and the uncontrolled indoor air environment is already identified for these components in LRA Tables 3.5.2-11 and 3.5.2-13. The staff noted that SRP-LR Section A.1.2.1 states that the aging effects to be considered should include those that result from plant shutdown, and thus aging management of the subject components exposed to treated water should be evaluated. However, the staff finds the applicant's age management approach acceptable for the subject debris screens, grating, bars, liners, and integral attachments because (a) the capability to detect degradation of the refueling bellows and the reactor well, dryer and separator pool, and cask loading pit liners is maintained through monitoring of the water levels of the spent fuel pool and reactor well in accordance with technical specifications and (b) the applicant will be using the One-Time Inspection program to verify the effectiveness of the Water Chemistry program for stainless steel components in the fuel pool cooling and cleanup system that are continuously exposed to the spent fuel pool water environment, which bounds the components that originally referenced item 3.5.1-78 and are exposed to the spent fuel pool water environment only during refueling.

The staff lacked sufficient information to find the response acceptable for the refueling bellows because the staff did not have adequate assurance that the above activities would be sufficient to manage aging of the bellows, which, caused by their thin walls and high residual stresses, may be particularly susceptible to degradation. By letter dated May 18, 2012, the staff issued RAI 3.5.2.11-1.1 requesting that the applicant describe actions that will be taken to manage the aging effects for the refueling bellows in the treated water environment or provide the basis for not performing an aging management review.

In its response dated May 31, 2012, the applicant stated that potential aging effects of the refueling bellows caused by exposure to treated water do not warrant management because the bellows are only exposed to water for two weeks each operating cycle, the bellows are not in low-flow or stagnant areas since the area is drained upon completion of the refueling, the normal indoor air environment is inerted with nitrogen, and heat from the RPV causes rapid evaporation of any moisture remaining in the bellows. The applicant also stated that operating experience reviews have not identified any failures or leakage from the type of refueling bellows used at LGS and any such failures could be detected by monitoring of water level in the spent fuel pool and reactor cavity and bellows leakage detection instrumentation that alarms in the main control room. The staff finds the response acceptable because, even if degradation of the bellows were to occur during the limited exposure to treated water, the bellows leakage detection instrumentation and control room alarm (as described in UFSAR Section 9.1.3.5), the monitoring of spent fuel pool and reactor cavity water level, and the one-time inspection of bounding stainless steel components continuously exposed to the spent fuel pool environment are capable of ensuring that degradation of the refueling bellows will be detected before loss of intended functions. The staff's concerns described in RAIs 3.5.2.11-1 and 3.5.2.11-1.1 are resolved.

The applicant stated that for item 3.5.1-78, the applicability is limited to the aging effect of loss of material. The staff noted that UFSAR Section 9.1.3 states the normal spent fuel pool design maximum temperature is 140 °F, but may exceed this temperature for 2.5 days to a peak temperature of 143 °F during refueling. The staff also noted that GALL Report Section IX.D states that stainless steel is subject to cracking caused by stress corrosion cracking at temperatures above 60 °C (140 °F). The staff further noted that, although not stated as an aging effect in AMR items in LRA Tables 3.5.2-11 and 3.5.2-13, cracking caused by stress corrosion cracking is effectively being managed by the aging management activities for loss of material in a manner consistent with GALL Report recommendations, which includes the use of the Water Chemistry program and monitoring of spent fuel pool water level and the leak chase channel drainage system. Therefore, the staff finds the applicant's determination acceptable.

The staff's evaluation of the Water Chemistry program is documented in SER Section 3.0.3.1.2. Based on its review of components associated with item 3.5.1-78 the staff finds the applicant's proposal to manage loss of material using the Water Chemistry program and monitoring of the spent fuel pool water level and leak chase channel drainage system acceptable because the Water Chemistry program establishes the plant water chemistry control parameters and their limits to mitigate the potential for aging and identifies the actions required if the parameters exceed the limits. Also, monitoring of the spent fuel pool water level and the leak chase channels is capable of verifying the effectiveness of water chemistry controls by detecting fuel pool liner and gate component degradation before loss of intended function.

The staff concludes that for LRA Item 3.5.1-78, 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 during the period of extended operation as required by 10 CFR 54.21(a)(3).

3.5.2.1.1 AMR Results Identified as Not Applicable

For LRA Table 3.5.1 items 3.5.1-15 through 3.5.1-20, 3.5.1-23, 3.5.1-26, 3.5.1-27, 3.5.1-32, 3.5.1-38, 3.5.1-39, 3.5.1-40, 3.5.1-43, 3.5.1-45, 3.5.1-46, 3.5.1-48, 3.5.1-50, 3.5.1-52 through 3.5.1-54, 3.5.1-62, 3.5.1-69, 3.5.1-73, 3.5.1-76, 3.5.1-79, and 3.5.1-84, the applicant claimed that they were not applicable. The staff reviewed the LRA and UFSAR and confirmed that the applicant's LRA does not have any AMR results applicable to these items.

For LRA Table 3.5.1 items 3.5.1-25, and 3.5.1-89, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to PWRs. The staff reviewed the SRP-LR, confirmed these items only apply to PWRs, and finds these items are not applicable to LGS.

LRA Table 3.5.1, item 3.5.1-68 addresses high-strength structural bolting. The GALL Report recommends GALL Report AMP XI.S3, "ASME Code Section XI, Subsection IWF," to manage cracking caused by SCC for this component group. The applicant stated that this item is not applicable because it does not use high-strength structural bolts subject to SCC in this application. The staff lacked sufficient information to evaluate the applicant's claim because a review of UFSAR Sections 3.8.3.1.2, "Reactor Pedestal," 3.8.6.2.1, "Structural Steel Materials," and 3A.7.1.2.2.1, "Downcomer Bracing System" state that high-strength structural steel bolting is used. The staff noted that RG 1.65, issued April 2010, states that when stud materials do not exceed 170 ksi, they are relatively immune to SCC. By letter dated January 18, 2012, the staff issued RAI 3.5.2.1.1-1 requesting the applicant to state whether any of the components described in the above three referenced UFSAR sections are within the scope of license renewal and whether the bolting tensile strength exceeds 170 ksi.

In its response, dated February 16, 2012, the applicant stated that the bolting discussed in UFSAR Section 3.8.3.1.2, is ring girder bolting constructed of ASME SA-540 Grade B23, Class 5 material having a specified tensile strength of 120 ksi, and UFSAR Section 3.8.4.6.2.1 lists A325 or A490 as the high-strength bolts used for structural steel, and SRP-LR Table 3.5-1, item 3.5.1-69 states that, "ASTM A 325, F1852, and ASTM A 490 bolts used in civil structures have not shown to be prone to SCC. SCC potential need not be evaluated for these bolts." The applicant also stated that UFSAR Section 3A.7.1.2.2.1 bolting is constructed of ASME SA 564, Type 630 with H1075 tempering heat treatment material having a specified tensile strength of 145 ksi.

The staff finds the applicant's response acceptable because bolting material cited in the RAI either does not exceed a tensile strength of 150 ksi, or the conservative tensile strength of 150 ksi, or the staff has stated that the material is not prone to SCC. The staff's concern described in RAI 3.5.2.1.1-1 is resolved.

3.5.2.1.2 Loss of Material (Spalling, Scaling)

LRA Table 3.5.1, item 3.5.1-56 addresses reinforced concrete exposed to water-flowing, which will be managed for loss of material (abrasion, cavitation and spalling, scaling). For the AMR item that cites generic note E, the LRA credits the Structures Monitoring program to manage the aging effect for reinforced concrete in the cooling tower basin. The GALL Report recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or FERC/US Army Corps of Engineers Dam Inspections and Maintenance Programs to ensure that this aging effect is adequately managed.

GALL Report AMP XI.S7 recommends using visual inspection by qualified engineers at intervals not to exceed 5 years to monitor for indications of concrete cracking, movements (e.g., settlement, heaving, and deflection), conditions at junctions with abutments and embankments, loss of material, increase in porosity and permeability, seepage, and leakage to manage aging. The staff noted that the Structures Monitoring program will manage the aging of reinforced concrete in the cooling tower structures subjected to water-flowing for indications of deterioration and distress, including evidence of leaching, loss of material, cracking, and loss of bond through visual inspections by qualified personnel, at inspection intervals not to exceed 5 years, in accordance with station procedures that have been enhanced for consistency with ACI 349.3R-02.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. In its review of components associated with item 3.5.1-56 for which the applicant cited note E, the staff finds the applicant's proposal to manage aging using the Structures Monitoring program acceptable because loss of material (abrasion, cavitation and spalling, scaling) will be managed through visual inspections conducted by qualified personnel at intervals not to exceed 5 years in accordance with recommendations in ACI 349.3R-02.

3.5.2.1.3 Loss of Preload and Loss of Material

LRA Table 3.5.1, items 3.5.1-80 and 3.5.1-88 address carbon, low-alloy, and stainless steel bolting exposed externally to either uncontrolled indoor air or treated water that will be managed for loss of preload because of self-loosening and loss of material caused by general, pitting, and crevice corrosion. For the AMR items that cite generic note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program to manage these aging effects for carbon, low-alloy, and stainless steel bolting. The GALL Report recommends GALL Report AMP XI.S6 "Structures Monitoring" program to ensure that these aging effects are adequately managed.

GALL Report AMP XI.S6 recommends using periodic visual inspections, at a frequency not to exceed 5 years, to monitor structural bolting for loose bolts, missing or loose nuts, and other conditions indicative of loss of preload to ensure that there is no loss of intended function between inspections. The staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program proposes to manage loss of preload and loss of material in carbon, low-alloy, and stainless steel bolting through annual visual inspections in accordance with ASME Code B30, which addresses construction, installation, operation, inspection, testing, and maintenance of cranes and related equipment. Structural components and bolting will be monitored for loss of material caused by corrosion, and bolted connections will be monitored for loss of preload.

The staff's evaluation of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program is documented in SER Sections 3.0.3.2.6. In its review of components associated with items 3.5.1-80 and 3.5.1-88, for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program acceptable because the bolting associated with cranes, hoists, and fuel handling and storage equipment will be inspected annually for indications of loss of preload and loss of material.

3.5.2.1.4 Loss of Material Caused by Pitting and Crevice Corrosion

LRA Table 3.5.1, item 3.5.1-85 addresses stainless steel bolting exposed to treated water (external) that will be managed for loss of material caused by pitting and crevice corrosion. For the AMR item that cites generic note E, the LRA credits the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program to manage the aging effect for stainless steel bolting for portions of the fuel preparation machine, which is partially exposed to treated water. The GALL Report recommends GALL Report AMP XI.S3 "ASME Code Section XI, Subsection IWF," to ensure that this aging effect is adequately managed.

GALL Report AMP XI.S3 recommends using periodic visual inspections of a specified number of component supports (including bolting), at an interval of 10 years to manage aging. The staff noted that the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program proposes to manage the aging of stainless steel bolting through annual visual inspections in accordance with ASME B30, which addresses construction, installation, operation, inspection, testing, and maintenance of cranes and related equipment.

The staff's evaluation of the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program is documented in SER Sections 3.0.3.2.6. In its review of components associated with item 3.5.1-85 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the Inspection of Overhead Heavy Load and Light Load (Related to Refueling) Handling Systems program acceptable because the stainless steel bolting associated with cranes, hoists, and fuel handling and storage equipment will be inspected annually for indications of loss of material.

3.5.2.1.5 Loss of Material

LRA Table 3.5.1, item 3.5.1-93 addresses stainless steel metal components, concrete anchors, and bolting exposed to outdoor air that will be managed for loss of material. For the AMR items that cite generic note E, the LRA credits the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program to manage the aging effect for stainless steel metal components, concrete anchors, and bolting. The GALL Report recommends GALL Report AMP XI.S6 "Structures Monitoring" program to ensure that this aging effect is adequately managed.

GALL Report AMP XI.S6 recommends using periodic visual inspections, at a frequency not to exceed 5 years, to monitor steel components for loss of material; concrete anchor bolts for loss of material, loose or missing nuts, and cracking of concrete around anchor bolts; and structural bolting for loose bolts, missing or loose nuts, and other conditions indicative of loss of preload, to ensure that there is no loss of intended function between inspections. The staff noted that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program, when enhanced, proposes to manage the aging of stainless steel metal components, concrete anchors, and bolting associated with the spray pond and pump house through visual inspections using guidance provided in RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program and ACI 349.3R-02.

The staff's evaluation of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER Section 3.0.3.2.18. In its review of components associated with item 3.5.1-93 for which the applicant cited generic note E, the staff finds the applicant's proposal to manage aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program acceptable because the stainless steel metal components, concrete anchors, and bolting associated with the spray pond and pump house will be inspected visually for loss of material using guidance provided in the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program and ACI 349.3R-02. The visual inspection interval and parameters monitored are consistent with those recommended in GALL Report AMP XI.S6.

3.5.2.1.6 Reduction or Loss of Isolation Function

LRA Table 3.5.1, item 3.5.1-94 addresses elastomer supports exposed to either uncontrolled indoor air or outdoor air that will be managed for reduction or loss of isolation function. For the AMR items that cite generic note E, the LRA credits the Structures Monitoring program to manage the aging effect for elastomer supports. The GALL Report recommends GALL Report AMP XI.S3, "ASME Code Section XI, Subsection IWF," program to ensure that this aging effect is adequately managed.

GALL Report AMP XI.S3 recommends performing VT-3 examinations for the elastomeric vibration elements and supplementing by feel to detect hardening if the vibration isolation element is suspect. The staff noted that the Structures Monitoring program, after enhancement, proposes to manage the aging of elastomeric supports through visual inspections of elastomeric vibration elements and structural seals for cracking, loss of material, and hardening. Visual inspections are to be supplemented by manipulation to detect hardening when vibration isolation function is suspect.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. In its review of components associated with item 3.5.1-94 for which the applicant cited generic note E, the staff finds that the applicant's proposal to manage aging using the Structures Monitoring program acceptable because reduction or loss of isolation function will be managed through visual examinations, supplemented by manipulation to detect hardening when vibration isolation function is suspect.
3.5.2.1.7 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed were not applicable. On the basis of its review, the staff concludes that the AMR results that the applicant claimed were not applicable are not applicable to LGS Units 1 and 2.

As discussed in SER Section 3.0.2.2, for those AMRs that the applicant claimed consistency with the GALL Report, the staff evaluated the applicant's claim of consistency. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent.

Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.5.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the structures and component supports components and provides information concerning how it will manage aging effects in the following three areas:

(1) PWR and BWR containments:

- aging of inaccessible concrete areas
- cracks and distortion because of increased stress levels from settlement; reduction of foundation strength, cracking, and differential settlement caused by erosion of porous concrete subfoundations if not covered by the Structures Monitoring program
- reduction of strength and modulus of concrete structures caused by elevated temperature
- loss of material caused by general, pitting, and crevice corrosion
- loss of prestress caused by relaxation, shrinkage, creep, and elevated temperature
- cumulative fatigue damage
- cracking caused by SCC
- cracking caused by cyclic loading
- loss of material (scaling, cracking, and spalling) caused by freeze-thaw

- cracking caused by expansion and reaction with aggregate and increase in porosity and permeability caused by leaching of calcium hydroxide

(2) safety-related and other structures and component supports:

- aging of structures not covered by the Structures Monitoring program
- aging management of inaccessible areas (below-grade inaccessible concrete areas of Groups 1-5, and 7-9 structures)
- reduction of strength and modulus of concrete structures caused by elevated temperature for Group 1-5 structures
- aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas)
- cracking caused by SCC and loss of material caused by pitting and crevice corrosion for Group 7 and 8 stainless steel tank liners
- aging of supports not covered by the Structures Monitoring program
- cumulative fatigue damage caused by cyclic loading

(3) QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.5.2.2. The staff's review of the applicant's further evaluation follows.

3.5.2.2.1 PWR and BWR Containments

3.5.2.2.1.1 Cracking and Distortion Caused by Increased Stress Levels from Settlement; Reduction of Foundation Strength, and Cracking Caused by Differential Settlement and Erosion of Porous Concrete Subfoundations

LRA Table 3.5.1, items 3.5.1-1 and 3.5.1-2, addresses concrete components exposed to either a soil or water-flowing environment. The GALL Report recommends GALL Report AMP XI.S2, "ASME Code Section XI, Subsection IWL" program to manage for cracks and distortion caused by increased stress levels from settlement, and the GALL Report XI.S6, "Structures Monitoring" program to manage for a reduction of foundation strength, cracking, and differential settlement caused by erosion of porous concrete subfoundations. The applicant stated that these items are not applicable because the LGS containments are founded on bedrock, LGS does not rely on a de-watering system, and LGS does not use porous concrete subfoundations. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.11 and 3.5, and finds it acceptable because the containment foundations are founded on bedrock, LGS does not employ a de-watering system, and LGS does not use porous concrete subfoundations.

3.5.2.2.1.2 Reduction of Strength and Modulus of Elasticity Caused by Elevated Temperature

LRA Table 3.5.1, item 3.5.1-3, addresses concrete structures exposed to either an air-indoor, uncontrolled or air-outdoor environment that are being managed for reduction of strength and modulus of elasticity because of elevated temperature exposure. The SRP-LR states that reduction in strength and modulus of concrete structures could occur for concrete structures caused by exposure to temperatures in excess of those specified in Subsection CC-3400 of ASME Code, Section III, Division 2, for general areas (150 °F) and local areas (200 °F). The applicant stated that this item is not applicable because concrete associated with the containment is not exposed to temperatures above these limits. The applicant also stated that containment average bulk temperature does not exceed 145 °F and that localized concrete temperatures exceeding 200 °F have not been reported. The staff reviewed the UFSAR to evaluate the applicant's claim and finds it acceptable because containment concrete temperatures are below the limits provided in Subsection CC-3400 of ASME Code Section III, Division 2, for both general and local areas.

3.5.2.2.1.3 Loss of Material Caused by General, Pitting, and Crevice Corrosion

(1) Steel elements of inaccessible areas for all types of PWR and BWR containments.

LRA Table 3.5.1, item 3.5.1-4 addresses inaccessible areas of steel elements (drywell shell, drywell head) exposed to either an uncontrolled indoor air or concrete environment. The GALL Report recommends GALL Report AMP XI.S1, "ASME Code Section XI, Subsection IWE," and GALL Report AMP XI.S4, "10 CFR Part 50, Appendix J," to manage for loss of material caused by general, pitting, and crevice corrosion. The applicant stated that this item is not applicable because LGS uses Mark II concrete containments and this item only applies to Mark III steel containments. The staff evaluated the applicant's claim by reviewing the GALL Report and finds it acceptable because this item only applies to BWR Mark III steel containments.

LRA Section 3.5.2.2.1.3 associated with LRA Table 3.5.1, item 3.5.1-5 addresses steel elements of accessible and inaccessible areas of containments exposed to either an uncontrolled indoor or treated water environment that will be managed for loss of material caused by general, pitting, and crevice corrosion by the ASME Code Section XI, Subsection IWE, and 10 CFR Part 50, Appendix J programs.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that LRA Table 3.5-1, item 3.5.1-5 will be addressed under the ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs to manage the loss of material of steel elements in both the accessible and inaccessible areas of the drywell and suppression pool liner, liner anchors, integral attachments, drywell head, and embedded shell, including the region shielded by the diaphragm floor. The applicant also stated that the LGS Mark II concrete containments drywell and suppression pool design does not include large ASME Code, Section XI, Subsection IWE liners or other surfaces that are inaccessible for inspection caused by coverage by permanent insulation such as certain PWRs, nor do they include areas under a concrete floor slab as is common in Mark I containments and certain PWRs. The applicant further stated that the majority of the LGS ASME Code, Section XI, Subsection IWE surfaces are accessible for inspection, the coated liner surfaces are inspected for coating defects such as blisters that could indicate corrosion of the carbon steel liner, and that there are limited areas that are inaccessible for inspection, including the thickened embedded steel structural weldment covered by the outer edges of the steel lined concrete diaphragm slab (drywell floor), and also the suppression pool floor liner areas covered by the suppression pool columns and areas behind the suction strainers. In addition, the applicant stated that the diaphragm slab concrete floor is lined with steel that is welded to the containment wall liner, the suppression pool concrete floor is lined with steel that is welded to the suppression pool wall liner such that there are no concrete to steel interface surfaces that would require a moisture barrier seal, and the LGS BWR Mark II concrete containment design does not result in corrosive materials contacting the liner. Also, the applicant stated that the primary containment atmosphere is inerted with nitrogen during operation, and that some general corrosion and pitting have been identified in underwater portions of the suppression pool that will be addressed during the period of extended operation by enhancing the ASME Code Section XI, Subsection IWE program. Finally, the applicant stated that while some general corrosion and pitting has been identified by ASME Code, Subsection IWE examinations, the corrosion is primarily in underwater portions of the suppression pool, the corrosion has not been significant, and the ASME Code Section XI, Subsection IWE program will be enhanced before the period of extended operation to address the conditions identified.

The staff reviewed the applicant's evaluation for consistency with SRP-LR Section 3.5.2.2.1.3 item 1 which states that loss of material caused by general, pitting, and crevice corrosion could occur in steel elements of inaccessible areas for all types of PWR and BWR containments exposed to an uncontrolled, indoor air or treated water environment. The SRP-LR also states that the existing program relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J, to manage this aging effect, and the GALL Report recommends further evaluation of plant-specific programs to manage this aging effect if corrosion is indicated from the ASME Code, Subsection IWE examinations. The staff noted that during regular inspections in accordance the applicant's ASME Code Section XI, Subsection IWE program some loss of material due general corrosion was identified in the suppression pool liner plate. The applicant performed further evaluation of this condition and determined that enhancement to the ASME Code Section XI, Subsection IWE aging management program is necessary to monitor and manage this degradation of the suppression pool liner plate. The staff reviewed this enhancement and determined it does not address the staff concern on how degradation in the coating can be used to determine the scope and extent of the augmented inspection of the liner plate condition and thickness. The details of the staff evaluation and concerns are described in SER Section 3.0.3.2.13. This item is unresolved and is currently being tracked as Open Item 3.0.3.2.13-1.

(2) Steel torus shell of Mark I containments

LRA Section 3.5.2.2.1.3 associated with LRA Table 3.5.1, item 3.5.1-6 addresses loss of material caused by general, pitting, and crevice corrosion in the steel torus shell of Mark I containments exposed to either an uncontrolled indoor air or treated water environment. The applicant stated that this item is not applicable because LGS uses a Mark II concrete containment incorporating a suppression pool and not a torus. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.11 and 3.5 and finds it acceptable because the LGS uses Mark II concrete containments that do not include a torus.

(3) Steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and interior surface of suppression chamber shell of Mark III containments

LRA Section 3.5.2.2.1.3 associated with LRA Table 3.5.1, item 3.5.1-7, addresses steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and the interior surface of the suppression chamber shell of Mark III containments exposed to either a treated water or uncontrolled indoor air environment that will be managed for loss of material caused by general, pitting, and crevice corrosion by the ASME Code Section XI, Subsection IWE program. The LRA further stated that item 3.5.1-7 is applicable to Mark I and Mark III steel containments and is not applicable to the LGS Mark II concrete containment; therefore, further evaluation of the plant-specific programs is not required for this item. The applicant also stated that the ASME Code Section XI, Subsection IWE program will be used to manage the loss of material of the LGS Mark II steel diaphragm floor liner, downcomers, and vacuum relief valve piping as addressed by item 3.5.1-31.

The criteria in SRP-LR Section 3.5.2.2.1.3, item 3, states that loss of material caused by general, pitting, and crevice corrosion could occur in steel torus ring girders and downcomers of Mark I containments, downcomers of Mark II containments, and the interior surface of the suppression chamber shell of Mark III containments exposed to either a treated water or an uncontrolled indoor air environment. The SRP-LR also states that the existing program relies on the ASME Code Section XI, Subsection IWE program to manage this aging effect, and recommends further evaluation of plant-specific programs to manage this aging effect if corrosion is significant.

The staff's evaluation of the ASME Code Section XI, Subsection IWE program is documented in SER Sections 3.0.3.2.13. The staff noted that the ASME Code Section XI, Subsection IWE program will be used to manage the loss of material of the LGS Mark II steel diaphragm floor liner, downcomer piping, and vent system. The staff reviewed SRP Section 3.5.2.2.1.3, item 3 and Table 3.5-1, item 7, associated GALL Report items II.B1.1.CP-109 and II.B.3.1.CP-158, and confirmed that LRA Table 3.5.1, item 3.5.1-7 is applicable to Mark I and Mark III containments only; therefore, further evaluation of this item at LGS is not required. In addition, the staff reviewed SRP Table 3.5.1, item 3.5.1-31 that address the pressure-retaining bolting and steel elements of the downcomer pipes, and found that ASME Code Section XI, Subsection IWE program is acceptable to manage aging for the loss of material caused by general, pitting, and crevice corrosion. The SRP-LR does not recommend further evaluation for this item. However, the applicant performed further evaluation and developed an acceptable inspection and recoating criteria based on original design calculations and supplemental analysis; however, the staff is concerned that this criterion is not identified in the applicant's aging management program. The details of the staff evaluation and concern are described in SER Section 3.0.3.2.1.3. This item is unresolved and is currently being tracked as Open Item 3.0.3.2.13-1.

Based on the programs identified, the staff concludes, pending resolution of Open Item 3.0.3.2.13-1, that the applicant's programs meet SRP-LR Section 3.5.2.2.1.3 criteria. For those items associated with LRA Section 3.5.2.2.1.3, the staff concludes, pending resolution of OI-3.0.3.2.13-1, that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.1.4 Loss of Prestress Caused by Relaxation, Shrinkage, Creep, and Elevated Temperature

LRA Section 3.5.2.2.1.4 associated with LRA Table 3.5.1, item 3.5.1-8 addresses loss of prestress caused by relaxation, shrinkage, creep, and elevated temperature in steel prestressing tendons exposed to either an air-indoor, uncontrolled or air-outdoor environment. The applicant stated that this item is not applicable because LGS concrete containments are not prestressed and, therefore, do not incorporate steel prestressing tendons, so a TLAA is not required. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.11 and 3.5 and finds it acceptable because the LGS containments use Mark II reinforced concrete containments that do not contain prestressing tendons.

3.5.2.2.1.5 Cumulative Fatigue Damage

LRA Section 3.5.2.2.1.5 associated with LRA Table 3.5.1, item 3.5.1-9, addresses the TLAAs (if CLB fatigue analyses exist) of suppression pool steel shells (including welded joints) and penetrations (including penetration sleeves, dissimilar metal welds, and penetration bellows) for all types of PWR and BWR containments and BWR vent header, vent line bellows, and downcomers exposed to either an uncontrolled indoor air, treated water, or outdoor air environment that will be managed for cumulative fatigue damage caused by cyclic loading by a TLAA.

TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c). The applicant addressed the further evaluation criteria of the SRP-LR by stating that fatigue is a TLAA as defined by 10 CFR 54.3. The applicant stated that evaluation of fatigue as a TLAA for the LGS primary containment liner and penetration sleeves, refueling bellows, and downcomers is addressed in LRA Sections 4.5, 4.6.7, and 4.6.8.

The staff's evaluation of the TLAAs is documented in SER Chapter 4. In its review of components associated with item 3.5.1-9, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using TLAAs is acceptable because the required TLAAs have been completed.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.1.5 criteria. For those items that apply to LRA Section 3.5.2.2.1.5, the staff concludes that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.1.6 Cracking Caused by SCC

LRA Table 3.5.1, item 3.5.1-10, and LRA Section 3.5.2.2.1.6 state that cracking caused by SCC is not an AERM for LGS stainless steel containment penetration sleeves, bellows, and dissimilar metal welds. The GALL Report indicates that the existing aging management relies on ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs to manage this aging effect. The GALL Report also recommends further evaluation for detection of the aging effect. The applicant stated that the LGS primary containment design does not use penetration bellows and LRA item 3.5.1-10 is not applicable to the LGS penetration sleeves that are carbon steel. In addition, the applicant indicated that while dissimilar welds and stainless steel CRD lines associated with penetrations exist, they are exposed to indoor air and are not exposed to a corrosive environment such that all the parameters necessary for SCC to occur are not present. The applicant further stated that LGS and industry operating experience has not identified cracking caused by SCC as an applicable aging effect for dissimilar metal welds on Mark II containment penetration sleeves and CRD lines in a BWR indoor-air environment.

In its review, the staff finds the applicant's claim acceptable because the applicant confirmed that Units 1 and 2 do not use penetration bellows, consistent with the staff's review of the UFSAR that does not identify any containment penetration bellow for the units. LRA item 3.5.1-10 is not applicable to the containment penetration sleeves made of carbon steel, consistent with the GALL Report. The applicant confirmed that the industry and plant-specific operating experience has not identified cracking caused by SCC of the dissimilar metal welds on the Mark II containment penetrations and stainless steel CRD line associated with penetrations exposed to BWR indoor air, and the applicant further confirmed that its containment penetrations are not exposed to a corrosive environment that involves all the factors necessary to cause SCC. In addition, the staff finds that the existing ASME Code Section XI, Subsection IWE and 10 CFR Part 50, Appendix J programs are applied to the containment penetration components as indicated in LRA item 3.5.1-35 to manage aging of these components.

3.5.2.2.1.7 Loss of Material (Scaling, Spalling) and Cracking Caused by Freeze-Thaw

LRA Section 3.5.2.2.1.7 associated with LRA Table 3.5.1, item 3.5.1-11 addresses loss of material (scaling, spalling) and cracking caused by freeze-thaw in concrete in inaccessible areas of dome, wall, basemat, ring girders, and buttresses exposed to a freeze-thaw environment. The applicant stated that this item is not applicable because the primary containments at LGS are enclosed and sheltered within an indoor air environment by reactor enclosures (secondary containments), and, therefore, are not subject to freeze-thaw conditions that would produce loss of material (spalling, scaling) or cracking. The staff evaluated the applicant's claim by reviewing LRA Sections 2.2.14 and 3.5 and finds it acceptable because the LGS containments use Mark II reinforced concrete containments that are enclosed by secondary containments and, therefore, are not exposed to environmental conditions (e.g., moisture and freeze-thaw temperature cycles) that would produce loss of material (scaling, spalling) or cracking.

3.5.2.2.1.8 Cracking Caused by Expansion from Reaction with Aggregates

LRA Section 3.5.2.2.1.8 associated with LRA Table 3.5.1, item 3.5.1-12 addresses cracking caused by expansion from reaction with aggregates in concrete in inaccessible areas (containment, dome, wall, basemat, ring girders, buttresses, and concrete fill-in annulus) exposed to any environment. The GALL Report notes that a plant-specific AMP is not required to manage cracking and expansion caused by reaction with aggregate or concrete in inaccessible areas if: (1) as described in NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests, as required, can demonstrate that those aggregates do not adversely react within concrete, or (2) for potentially reactive aggregates, aggregate concrete reaction is not significant if it is demonstrated that the in-place concrete can perform its intended function.

The applicant stated that this item is not applicable because fine and course aggregates used in the concrete conform to ASTM C33, petrographic examinations of aggregates were performed in accordance with ASTM C295, ASTM C289, and other ASTM tests were conducted demonstrating that reactive aggregates were not used, and the concrete structures were constructed in accordance with ACI 301, ACI 318, and ACI 605 recommendations. The staff evaluated the applicant's claim by reviewing UFSAR Section 3.8.6 and finds it acceptable because the aggregate materials were evaluated for potential reactivity using investigations, tests, and petrographic examinations recommended in NUREG-1557.

3.5.2.2.1.9 Increase in Porosity and Permeability caused by Leaching of Calcium Hydroxide and Carbonation

LRA Section 3.5.2.2.1.9 associated with LRA Table 3.5.1, items 3.5.1-13 and 3.5.1-14 addresses concrete in inaccessible areas (containment, dome, wall, basemat, and ring girders, and buttresses) exposed to water-flowing environment. The GALL Report notes that a plant-specific AMP is not required to manage increase in porosity and permeability and loss of strength caused by leaching of calcium hydroxide and carbonation of concrete in inaccessible areas if: (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation, and (2) evaluation determines that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on intended function of the concrete structure.

The applicant stated that this item is not applicable because inspections of LGS primary containment structures have not identified any leaching in the accessible primary containment areas that may affect the intended function. The applicant also stated that the primary containment is completely enclosed and sheltered as a result of being located within the indoor air environment of the reactor enclosure (secondary containment), the interior of the primary containment is lined with steel, and there is no flowing water through concrete that could be associated with this aging effect. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.11 and 3.5 and finds it acceptable because the LGS containments are completely enclosed and sheltered as a result of being located within the indoor air environment of the reactor enclosures, no evidence of leaching has been observed on accessible surfaces that could impact intended functions, and the containment is not subjected to flowing water.

3.5.2.2.2 Safety-Related and Other Structures and Component Supports

3.5.2.2.2.1 Aging Management of Inaccessible Areas

(1) Loss of material (spalling, scaling) and cracking caused by freeze-thaw in below-grade inaccessible concrete areas of Groups 1-2, 5, and 7-9 structures.

    LRA Section 3.5.2.2.2.1 associated with LRA Table 3.5.1, item 3.5.1-42 addresses inaccessible areas of Groups 1-3, 5, and 7-9 concrete structures exposed to freeze-thaw conditions, which will be managed for loss of material (spalling, scaling) and cracking by the Structures Monitoring program. The criteria in SRP-LR Section 3.5.2.2.2.1 item 1 states that loss of material (spalling, scaling) and cracking could occur for below-grade inaccessible areas of Groups 1-3, 5, and 7-9 concrete structures exposed to freeze-thaw. The SRP-LR also states that further evaluation is required for plants that are located in moderate to severe weathering conditions (weathering index greater than 100 day-inches per year) as noted in NUREG-1557. The GALL Report states that a plant-specific program is not required if documented evidence confirms that the existing concrete had an air content of 3 percent to 8 percent and subsequent inspection did not exhibit degradation related to freeze-thaw. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Structures Monitoring program will be used to manage loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas. The applicant also stated that the concrete structures at LGS are designed and constructed in accordance with ACI 318-71 and ACI 301-66, and the concrete mixture design provides for low permeability and adequate air entrainment (3 percent to 7 percent) resulting in good freeze-thaw resistance. The applicant further stated that operating experience has not identified significant loss of material (spalling, scaling) and cracking due freeze-thaw for in-scope reinforced concrete structures and the condition of accessible and above-grade concrete is used as an indicator for the condition of the inaccessible and below-grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. In addition, the applicant stated that in the event that unacceptable conditions caused by freeze thaw are identified in the accessible areas of structures, procedures require that the extent of the condition be determined and additional inspections or evaluations would address inaccessible and below grade portions of any affected structure, and LGS will examine exposed portions of the below-grade concrete when excavated for any reason in accordance with the Structures Monitoring program.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.16. The staff noted that concrete structures at LGS are designed and constructed in accordance with ACI 318-71 and ACI 301-66 and the concrete mixture design provides for low permeability and adequate air entrainment (3 percent to 7 percent) such that the concrete has good freeze-thaw resistance. Operating experience has not identified any freeze-thaw damage that would impact a structure's intended function. In its review of items associated with 3.5.1-42, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Structures Monitoring program is acceptable because the concrete structures at LGS are designed and constructed in accordance with ACI 318-71 and ACI 301-66, the concrete mixture design provides for low permeability and adequate air entrainment (3 percent to 7 percent) such that the concrete has good freeze-thaw resistance, accessible concrete structures will be managed for this aging effect under the Structures Monitoring program with results used as an indicator for the condition of inaccessible and below-grade concrete structures, and LGS will examine exposed portions of the below-grade concrete when excavated for any reason in accordance with the Structures Monitoring program.

(2) Cracking caused by expansion and reaction with aggregates of Groups 1-5 and 7-9 structures.

LRA Table 3.5.1, item 3.5.1-43, addresses concrete in inaccessible areas of Groups 1-5, and 7-9 concrete structures exposed to any environment. The GALL Report recommends further evaluation to determine if a plant-specific AMP is needed. The GALL Report also notes that a plant-specific AMP is not required to manage cracking and expansion caused by reaction with aggregate or concrete in inaccessible areas if: (1) as described in NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests, as required, can demonstrate that those aggregates do not adversely react within concrete; or (2) for potentially reactive aggregates, aggregate concrete reaction is not significant if it is demonstrated that the in-place concrete can perform its intended function. The applicant stated that this item is not applicable because fine and course aggregates used in the concrete conform to ASTM C33, petrographic examinations of aggregates were performed in accordance with ASTM C295, ASTM C289 and other ASTM tests were conducted that demonstrate that reactive aggregates were not used, and the concrete structures were constructed in accordance with ACI 301, ACI 318, and ACI 605 recommendations. The staff evaluated the applicant's claim by reviewing UFSAR Section 3.8.6 and finds it acceptable because the aggregate materials were evaluated for potential reactivity using investigations, tests, and petrographic examinations recommended in NUREG-1557.

(3) Cracking and distortion because of increased stress levels from differential settlement for Groups 1-9 structures and reduction in foundation strength and cracking caused by differential settlement and erosion of porous concrete subfoundations of Groups 1-3, and 5-9 structures.

LRA Section 3.5.2.2.2.1 associated with LRA Table 3.5.1, item 3.5.1-44, addresses concrete in inaccessible areas of Groups 1-9 structures exposed to differential settlement that will be managed for cracking and distortion by the Structures Monitoring program. The criteria in the SRP-LR 3.5.2.2.2.1 item 3 states that cracking and distortion could occur in Groups 1-9 concrete structures exposed to differential settlement or porous concrete subfoundations. The GALL Report recommends further evaluation under AMP XI.S6, "Structures Monitoring" to manage differential settlement for this component group and if a de-watering system is relied upon for control of settlement, then proper functioning of the de-watering system is required through the period of extended operation. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Structures Monitoring program will be used to manage cracking and distortion of concrete in accessible and inaccessible locations for structures founded on soil, all Category I plant facilities are founded on bedrock, and LGS does not rely on a de-watering system.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. The staff noted that the Structures Monitoring program will be used to manage cracking and distortion of concrete in accessible and inaccessible locations for structures founded on soil, all Category I plant facilities are founded on bedrock, and LGS does not rely on a de-watering system. In its review of components associated with item 3.5.1-44, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Structures Monitoring program is acceptable because it is the AMP recommended in the GALL Report, LGS Category I facilities are founded on bedrock, and LGS does not rely on a de-watering system.

LRA Table 3.5.1, items 3.5.1-45 and 3.5.1-46, addresses concrete in inaccessible areas of Groups 1-3 and 5-9 structures exposed to differential settlement and erosion of porous concrete subfoundations. The GALL Report recommends further evaluation under AMP XI.S6, "Structures Monitoring" to manage differential settlement for this component group if a de-watering system is relied upon for control of settlement. The applicant stated that these items are not applicable because the LGS containments are founded on bedrock, LGS does not rely on a de-watering system, and LGS does not use porous concrete subfoundations. The staff evaluated the applicant's claim by reviewing LRA Sections 2.4.11 and 3.5 and finds it acceptable because the containment foundations are founded on bedrock, LGS does not employ a de-watering system, and LGS does not use porous concrete subfoundations.

(4) Increase in porosity and permeability and loss of strength caused by leaching of calcium hydroxide and carbonation for Groups 1-5 and 7-9 structures

LRA Section 3.5.2.2.2 associated with LRA Table 3.5.1, item 3.5.1-47 addresses concrete in inaccessible areas, exterior above- and below-grade, of Groups 1-5 and 7-9 structures exposed to water-flowing that will be managed for increase in permeability and loss of strength because of leaching of calcium hydroxide and carbonation by the Structures Monitoring program. The criteria in SRP-LR states that a plant-specific AMP is not required to manage increase in porosity and permeability and loss of strength because of leaching of calcium hydroxide and carbonation of concrete in inaccessible areas if: (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation, and (2) evaluation determines that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on the intended function of the concrete structure.

The applicant addressed the further evaluation criteria of the SRP-LR by stating that the Structures Monitoring program will be used to manage increase in porosity and permeability, and loss of strength for concrete and exterior above- and below-grade accessible and inaccessible concrete and foundations. The applicant also stated that leaching of calcium hydroxide is applicable for a water-flowing environment, which may occur to a limited extent in accessible or inaccessible portions of in-scope structures. The applicant further stated that the effects of carbonation have not been observed on LGS concrete, and operating experience has found that increase in porosity and permeability and loss of strength caused by these mechanisms is not significant and is, therefore, adequately managed by the Structures Monitoring program. In addition, the applicant stated that the reinforced concrete is designed and constructed to meet ACI and ASTM Specifications, including ACI 318, to produce durable concrete, and LGS will examine exposed portions of the below-grade concrete when excavated for any reason in accordance with the Structures Monitoring program.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. In its review of items associated with 3.5.1-47, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the Structures Monitoring program is acceptable because it is the AMP recommended in the GALL Report, the reinforced concrete is designed and constructed to meet ACI and ASTM specifications, including ACI 318, to produce durable concrete, the effects of carbonation have not been observed on LGS concrete, operating experience has found that increase in porosity and permeability and loss of strength caused by these mechanisms is not significant, and exposed portions of below-grade concrete will be examined when excavated for any reason.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.1 criteria. For those items that apply to LRA Section 3.5.2.2.2.1, the staff concludes that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2.2 Reduction of Strength and Modulus Caused by Elevated Temperatures

LRA Table 3.5.1, item 3.5.1-48, addresses reduction in strength and modulus of elasticity of Groups 1-5 concrete structures that could result because of elevated temperature exposure. The GALL Report recommends further evaluation under a plant-specific program for concrete structures exposed to temperatures in excess of those specified in Subsection CC-3400 of ASME Code, Section III, Division 2 for general areas (150 °F) and local areas (200 °F). The applicant stated that this item is not applicable because concrete associated with the Groups 1-5 concrete structures is not exposed to temperatures above these limits. The applicant also stated that containment average bulk temperature does not exceed 145 °F for Group 4 structures within the primary containment, Group 5 structures (i.e., refuel floor and spent fuel storage pool) are part of the reactor enclosure, which is a Group 1 structure, and the spent fuel pool water temperature is maintained below 140 °F under normal plant operating conditions. The applicant further stated that Groups 1, 3, and 4 concrete structural components are not subject to local temperatures greater than 200 °F, process piping operating at temperatures greater than 200 °F is insulated through penetrations, and plant operating experience has not identified elevated general or local area temperatures of concern to concrete structural components. The staff evaluated the applicant's claim and finds it acceptable because, as noted in the UFSAR, concrete temperatures are below the limits provided in Subsection CC-3400 of ASME Code Section III, Division 2, for both general and local areas.

3.5.2.2.2.3 Aging Management of Inaccessible Areas for Group 6 Structures

SRP-LR Section 3.5.2.2.2.3 addresses aging management of inaccessible areas for Group 6 structures (below-grade inaccessible concrete areas) and recommends further evaluation for inaccessible areas of certain Group 6 structure/aging effect combinations as identified below whether they are covered by inspections in accordance with the GALL Report, Chapter XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or FERC/US Army Corps of Engineers dam inspection and maintenance procedures.

(1) Loss of material (spalling, scaling) and cracking caused by freeze-thaw that could occur in below-grade inaccessible concrete areas of Group 6 structures.

LRA Section 3.5.2.2.2.3 associated with LRA Table 3.5.1, item 3.5.1-49, addresses below-grade concrete components of Group 6 structures (inaccessible areas) and exterior above- and below-grade foundation and interior slab concrete exposed to outdoor air environment that will be managed for loss of material (spalling, scaling) and cracking caused by freeze-thaw by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The criteria in SRP-LR 3.5.2.2.3 states that loss of material (spalling, scaling) and cracking caused by freeze-thaw could occur in below-grade inaccessible concrete areas of Group 6 structures and recommends further evaluation of this aging effect for inaccessible areas for plants located in moderate to severe weathering conditions. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program will be used to manage loss of material (spalling, scaling) and cracking in both accessible and inaccessible areas. The applicant also stated that the LGS Group 6 structures are located in a region where weathering conditions are considered; however, these concrete structures are designed and constructed in accordance with ACI 318-71 and

ACI 301-66 as described in the UFSAR that provides for low permeability and adequate air entrainment (3 percent to 7 percent) such that the concrete has good freeze-thaw resistance. The applicant further stated that operating experience review of structural concrete for in-scope structures has not identified significant loss of material (spalling, scaling) and cracking caused by freeze-thaw. The applicant further stated that the condition of accessible and above-grade concrete is used as an indicator of the condition of the inaccessible and below-grade structural components and provides reasonable assurance that degradation of inaccessible structural components will be detected before a loss of an intended function. The applicant stated that LGS examines exposed portions of the below-grade concrete, when excavated for any reason in accordance with the Structures Monitoring program.

The staff's evaluation of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER Section 3.0.3.2.18. The staff noted that concrete structures at LGS are designed and constructed in accordance with ACI 318-71 and ACI 301-66 and the concrete mixture design provides for low permeability and adequate air entrainment (3 percent to 7 percent) such that the concrete has good freeze-thaw resistance, and operating experience has not identified any freeze-thaw damage that would affect a structure's intended function. In its review of items associated with 3.5.1-49, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is acceptable because: (1) the concrete structures at LGS are designed and constructed in accordance with ACI 318-71 and ACI 301-66, (2) the concrete mixture design provides for low permeability and adequate air entrainment (3 percent to 7 percent) such that the concrete has good freeze-thaw resistance, (3) accessible concrete structures will be managed for this aging effect under the Structures Monitoring program with results used as an indicator for the condition of inaccessible and below-grade concrete structures, and (4) LGS will examine exposed portions of the below-grade concrete when excavated for any reason in accordance with the Structures Monitoring program.

(2) Cracking caused by expansion and reaction with aggregates that could occur in below-grade inaccessible concrete areas of Group 6 structures

LRA Table 3.5.1, item 3.5.1-50 addresses concrete in inaccessible areas of Group 6 concrete structures exposed to any environment. The GALL Report recommends further evaluation to determine if a plant-specific AMP is needed. The GALL Report also states that a plant-specific AMP is not required to manage cracking and expansion caused by reaction with aggregate or concrete in inaccessible areas if: (1) as described in NUREG-1557, investigations, tests, and petrographic examinations of aggregates performed in accordance with ASTM C295 and other ASTM reactivity tests, as required, can demonstrate that those aggregates do not adversely react within concrete; or (2) for potentially reactive aggregates, aggregate concrete reaction is not significant if it is demonstrated that the in-place concrete can perform its intended function. The applicant stated that this item is not applicable because fine and course aggregates used in the concrete conform to ASTM C33, petrographic examinations of aggregates were performed in accordance with ASTM C295, ASTM C289 and other ASTM tests were conducted that demonstrate that reactive aggregates were not used, the concrete structures were constructed in accordance with ACI 318, and plant operating experience has not found cracking associated with expansion caused by reaction with aggregates on LGS Group 6 concrete structures. The applicant also stated that the RG 1.127, "Inspection of Water-Control Structures Associated with Nuclear Power Plants" AMP will continue to inspect and monitor Group 6 concrete structures for cracking caused by any mechanism. The staff evaluated the applicant's claim by reviewing UFSAR Section 3.8.6 and finds it acceptable because the aggregate materials were evaluated for potential reactivity using investigations, tests, and petrographic examinations recommended in NUREG-1557, operating experience has not identified cracking associated with reactive aggregates, and structures will be managed for this aging effect by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program.

(3) Increase in porosity and permeability and loss of strength caused by leaching of calcium hydroxide and carbonation that could occur in below-grade inaccessible concrete areas of Group 6 structures

LRA Section 3.5.2.2.2 associated with LRA Table 3.5.1, item 3.5.1-51 addresses concrete in inaccessible areas of Group 6 concrete structures exposed to flowing water, which will be managed for increase in porosity and permeability and loss of strength caused by leaching of calcium hydroxide and carbonation by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The criteria in SRP-LR states that further evaluation is required to determine if a plant-specific AMP is required to manage increase in porosity and permeability and loss of strength caused by leaching of calcium hydroxide and carbonation of concrete in inaccessible areas. The SRP-LR also states that a plant-specific AMP is not required if: (1) there is evidence in the accessible areas that the flowing water has not caused leaching and carbonation, and (2) evaluation determines that the observed leaching of calcium hydroxide and carbonation in accessible areas has no impact on intended function of the concrete structure. The applicant addressed the further evaluation criteria of the SRP-LR by stating that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program will be used to manage increase in porosity and permeability and loss of strength caused by leaching and carbonation for Group 6 structures for accessible and inaccessible above and below grade and foundation concrete. The applicant also stated that leaching of calcium hydroxide is applicable for a flowing water environment, which may occur to a limited extent in accessible or inaccessible portions of in-scope structures. The applicant further stated that the effects of carbonation have not been observed on LGS concrete and operating experience has found that increase in porosity and permeability and loss of strength caused by these mechanisms is not significant; therefore, it is adequately managed by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. In addition, the applicant stated that the reinforced concrete is designed and constructed to meet ACI and ASTM Specifications, including ACI 318, to produce durable concrete, and LGS will examine exposed portions of the below-grade concrete when excavated for any reason in accordance with the Structures Monitoring program.

The staff's evaluation of the Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER Section 3.0.3.2.18. The staff noted that the LGS reinforced concrete is designed and constructed to meet ACI and ASTM specifications, including ACI 318, to produce durable concrete, the effects of carbonation have not been observed on LGS concrete, operating experience has found that increase in porosity and permeability and loss of strength caused by these mechanisms is not significant, and exposed portions of below-grade concrete will be examined when excavated for any reason. In its review of items associated with 3.5.1-51, the staff finds that the applicant has met the further evaluation criteria, and the applicant's proposal to manage aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is acceptable because the reinforced concrete is designed and constructed to meet ACI and ASTM Specifications, including ACI 318, to produce durable concrete, the effects of carbonation have not been observed on LGS concrete, operating experience has found that increase in porosity and permeability and loss of strength caused by these mechanisms is not significant, and exposed portions of below-grade concrete will be examined when excavated for any reason.

Based on the programs identified, the staff concludes that the applicant's programs meet SRP-LR Section 3.5.2.2.2.3 criteria. For those items that apply to LRA Section 3.5.2.2.2.3, the staff concludes that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.5.2.2.2.4 Cracking Caused by Stress Corrosion Cracking, and Loss of Material caused by Pitting and Crevice Corrosion

LRA Section 3.5.2.2.4, associated with LRA Table 3.5.1, item 3.5.1-52 addresses cracking and loss of material caused by pitting and crevice corrosion of Groups 7 and 8 stainless steel tank liners exposed to standing water. The applicant stated that this item is not applicable because LGS does not have Group 7 or Group 8 structures. The staff reviewed LRA Section 2.4 and the UFSAR and confirmed that the applicant's LRA does not have any AMR results that are applicable to these items.

3.5.2.2.2.5 Cumulative Fatigue Damage Caused by Fatigue

LRA Section 3.5.2.2.2.5, which is associated with LRA Table 3.5.1, item 3.5.1.53, addresses cumulative fatigue damage caused by cyclic loading in component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3 component supports exposed to uncontrolled indoor air. The applicant stated its CLB does not contain any fatigue analysis for component support members, bolted connections, or support anchorage to building structures. The staff reviewed the LGS Units 1 and 2 UFSAR and LRA Section 4 and confirmed that the applicant's CLB does not contain fatigue analyses that were identified as TLAAs as required by 10 CFR 54.21(c)(1) for component support members, anchor bolts, and welds for Groups B1.1, B1.2, and B1.3; therefore, the staff finds the applicant's claim acceptable.

3.5.2.2.3 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.5.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Tables 3.5.2-1 through 3.5.2-17, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.
In LRA Tables 3.5.2-1 through 3.5.2-17, the applicant indicated, via notes F through J, that the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether 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. The staff's evaluation is documented in the following sections.

3.5.2.3.1 220 and 500 kV Substations – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-1, which summarizes the results of AMR evaluations for 220 kV and 500 kV substations component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.5.2.3.2 Admin Building Shop and Warehouse – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-2, which summarizes the results of AMR evaluations for the admin building shop and warehouse component groups.

In LRA Tables 3.5.2-2, 3.5.2-3, and 3.5.2-16, the applicant stated that for polyvinyl chloride (PVC) roofing scuppers exposed to outdoor air, there is no aging effect and no AMP is proposed. The AMR items cite generic note J.

The staff reviewed the associated items in the LRA and could not confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff lacked sufficient information to conclude that no aging management is required for exposure to the outdoor air environment because the type of PVC material could influence the effect of exposure to outdoor UV light. By letter dated January 18, 2012 the staff issued RAI 3.5.2.3.2-1 requesting the applicant to state the specific type of PVC material used in the roofing scuppers within the scope of license renewal and the basis for why exposure to outdoor UV does not require age managing of these components.

In its response, dated February 16, 2012, the applicant stated that the specific PVC compound that is used for the roofing scuppers is not known. The PVC material is a commercial grade product and is assumed to not contain additives that would inhibit UV deterioration. The potential aging effect of PVC caused by sunlight UV is cracking caused by a change in material properties. Cracking is unlikely to prevent the scuppers from directing flow through the concrete opening; however, the PVC roofing scuppers will be managed for cracking by the Structures Monitoring AMP. The applicant revised LRA Tables 3.5.2-2, 3.5.2-3, and 3.5.2-16 to reflect cracking as an AERM for these items and designated the Structures Monitoring program to manage the aging.

The staff finds the applicant's response acceptable because the applicant identified the correct aging effect, cracking, for a polymeric component exposed to outdoor UV and will manage this aging using the Structures Monitoring program, which conducts visual inspections capable of detecting cracking on a 5-year inspection schedule. The staff's concern described in RAI 3.5.2.3.2-1 is resolved. However, LRA Section B.2.1.35, Structures Monitoring, program Description states, "Elastomers will be monitored for hardening, shrinkage and a loss of sealing" and does not address polymeric materials. In addition, Enhancement No. 2 lists newly added components. The staff noted that this enhancement was not updated to include roofing scuppers. By letter dated April 5, 2012, the staff issued followup RAI 3.5.2.3.2-1.1 requesting the applicant to revise LRA Section B.2.1.35 to include polymeric materials being managed for cracking and add roofing scuppers to Enhancement No. 2.

In its response, dated April 13, 2012, the applicant stated that LRA Section A.2.1.35 and Enhancement No. 2 for the Structures Monitoring program were revised to include roofing scuppers. In addition LRA Section B.2.1.35 was revised to state that PVC roof scuppers are monitored for cracking.

The staff finds the applicant's response acceptable because the Structures Monitoring program and Enhancement No. 2 were revised to include the component and its aging effect. The staff's concern described in RAI 3.5.2.3.2-1.1 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.3 Auxiliary Boiler and Lube Oil Storage Enclosure – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-3, which summarizes the results of AMR evaluations for the admin building shop and warehouse component groups.

The staff's evaluation for PVC roofing scuppers exposed to outdoor air and cite generic note J, is documented in Section 3.5.2.3.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.4 Circulating Water Pump House – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-4, which summarizes the results of AMR evaluations for circulating water pump house component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.5.2.3.5 Component Supports Commodities Group – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-5, which summarizes the results of AMR evaluations for component supports commodities group. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.5.2.3.6 Control Enclosure – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-6, which summarizes the results of AMR evaluations for control enclosure component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.5.2.3.7 Cooling Towers – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-7, which summarizes the results of AMR evaluations for the cooling towers component groups.

In LRA Table 3.5.2-7, the applicant stated that the above-grade exterior and interior (accessible) reinforced concrete, including basin curb wall, inlet, and outlet walls, and concrete foundation (accessible) (basin slab) exposed to water-flowing will be managed for cracking, loss of bond, loss of material (spalling, scaling), and increase in porosity and permeability, by the Structures Monitoring program. The AMR items cite generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which addresses reinforced concrete water-control structures exposed to water-flowing and recommends GALL Report AMP XI.S7, "Regulatory Guide 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants," or the FERC US Army Corps of Engineers dam inspections and maintenance programs to manage aging effects. The applicant addressed the GALL Report identified aging effects for this component, material and environment combination in AMR items in LRA Table 3.5.2-7.

The staff's evaluation of the Structures Monitoring program is documented in SER Section 3.0.3.2.17. The staff noted that under the Structures Monitoring program, structures and structural components are inspected by qualified personnel in accordance with station procedures, which will be enhanced for consistency with ACI 349.3R-02. The staff also noted that the concrete structures are inspected for indications of deterioration and distress including evidence of leaching, loss of material, cracking, and loss of bond as identified in ACI 201.1R, "Guide for Making a Condition Survey of Existing Buildings." The staff further noted that the Structures Monitoring program addresses environments of outdoor air, uncontrolled indoor air, treated water, raw water, water-flowing, and ground water and soil. The staff finds the applicant's proposal to manage aging using the Structures Monitoring program acceptable because the reinforced concrete structures associated with the cooling towers will be managed for cracking, loss of bond, and loss of material (spalling, scaling) through inspections by qualified personnel, at inspection intervals not to exceed 5 years, in accordance with station procedures that have been enhanced for consistency with ACI 349.3R-02.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.8 Diesel Oil Storage Tank Structures – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-8, which summarizes the results of AMR evaluations for diesel oil storage tank structures component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.5.2.3.9 Emergency Diesel Generator Enclosure – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-9, which summarizes the results of AMR evaluations for EDG enclosure component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

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

The staff reviewed LRA Table 3.5.2-10, which summarizes the results of AMR evaluations for the piping and component insulation commodity group.

In LRA Table 3.5.2-10, the applicant stated that for calcium silicate, fiberglass, foamed plastic, insulation cement and finishing cement, caulking and lagging adhesive, and insulation jacketing exposed to outdoor air, there is no aging effect and no AMP is proposed. The AMR items cite generic note J.

In LRA Table 3.5.2-10, the applicant stated that for calcium silicate, cellular glass, ceramic fiber, fiberglass, fiberglass (molded), foamed plastic, Min-K, mineral fiber and NUKON insulation, and insulation jacketing, cement and finishing cement exposed to uncontrolled indoor air, there is no aging effect and no AMP is proposed. The staff noted that the insulation jacketing materials are constructed of caulking adhesive, lagging adhesive, fiberglass cloth (including silicone coated fiberglass cloth), or plastic mastic. The AMR items cite generic notes F and J.

The staff reviewed the associated items in the LRA and could not confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff lacked sufficient information to conclude that no aging management is required for these components for the following reasons. The staff could not determine the product form, installation, function, or the specific material of construction of Min-K insulation. By letter dated January 18, 2012, the staff issued RAI 3.5.2.3.10-2 requesting the applicant to provide sufficient detail on the function and material of fabrication for Min-K insulation for the staff to independently evaluate and conclude that there is no AERM for this component.

In its response, dated February 16, 2012, the applicant stated that:

> Min-K is an insulation material consisting of fused silica particles combined with titanium dioxide and glass fibers, manufactured by Johns-Manville Co. Min-K flexible insulation material is used in applications where limited clearances or obstructions exist caused by its low thermal conductivity. Min-K insulation is applied in blanket form and covered with aluminum jacketing secured with aluminum, galvanized steel, or stainless steel straps. Min-K insulation is not subject to aging effects requiring management for the uncontrolled indoor air environment used as shown in Table 3.5.2-10 of the LGS LRA.

The staff finds the applicant's response acceptable because in its response to RAI 3.0.2-1, provided by letter dated February 15, 2012, the applicant stated that for all the AMR items in the LRA, the environment of uncontrolled indoor air contains no humidity, condensation, moisture or contaminants, and the Min-K insulation, as well as the other insulation and jacket components, are composed of materials that in the absence of moisture and outdoor UV will not degrade.

The staff's concern described in RAI 3.5.2.3.2.10-2 is resolved.

The staff noted that LRA Table 3.0-2 states that the uncontrolled indoor air environment can result in the surfaces of components being wet. Given the definition of the uncontrolled indoor air environment, it was not clear to the staff how water would not accumulate in the insulation material during periods when insulated systems are at ambient shutdown conditions. The staff also noted that UFSAR Section 5.2.3.2.4 describes the compatibility of thermal insulation to the underlying external surfaces of the piping it encloses; however, it is not clear to the staff that this UFSAR section is applicable to insulation materials not associated with the RCPB. The staff further noted that LRA Table 3.3.2-8, Emergency Diesel Generator System, and LRA Table 3.4.2-2, Condensate System, have stainless steel components exposed to the outdoor air environment that could be insulated. Therefore, the staff lacked sufficient information to conclude that there are no AERM associated with the components. By letter dated January 18, 2012, the staff issued RAI 3.5.2.3.10-3 requesting the applicant to state the basis for why the insulation materials exposed to uncontrolled indoor air listed in LRA Table 3.5.2-10 will not accumulate moisture resulting in degradation of its thermal insulation function, state whether UFSAR Section 5.2.3.2.4 applies to all insulation within the plant, or state the basis for why deleterious compounds (e.g., chlorides, halogens) will not leach out of the insulation and cause SCC or loss of material for the components it encloses. The applicant was also asked to state whether the stainless steel components exposed to outdoor air in LRA Tables 3.3.2-8 and 3.4.2-2 are insulated, and if they are insulated state the basis for why deleterious compounds (e.g., chlorides, halogens) will not leach out of the insulation and cause SCC of the stainless steel materials.

In its response to RAI 3.0.2-1, which is discussed in SER Section 3.0.1.2, the applicant stated that for all the AMR items in the LRA, the environment of uncontrolled indoor air contains no humidity, condensation, moisture, or contaminants. The applicant's response to

RAI 3.5.2.3.10-3, provided by letter dated February 16, 2012, states that UFSAR Section 5.2.3.2.4 does not apply to all insulation in the plant; however, its insulation specification requires that all insulating materials for stainless steel must meet RG 1.36, "Nonmetallic Thermal Insulation for Austenitic Stainless Steel," which includes controls to preclude deleterious compounds (e.g., chlorides, halogens). The response to RAI 3.5.2.3.1-3 also stated that the outdoor EDG stainless steel exhaust piping is not insulated, and the CST isolation stainless steel valves are heat traced and insulated, this insulation is constructed of glass fiber material within a sealed aluminum jacket, and the insulation meets RG 1.36 recommendations.

The staff finds the applicant's response acceptable because insulation and jacket components are composed of materials that in the absence of moisture and outdoor UV will not degrade and plant-specific insulation specifications ensure that deleterious materials are not contained within the insulation. The staff's concern described in RAI 3.5.2.3.2-10-3 is resolved.
The staff reviewed the associated items in the LRA and could not confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff lacked sufficient information to conclude that no aging management is required for exposure to the outdoor air environment caused by the potential impact of UV exposure and water intrusion. By letter dated January 18, 2012, the staff issued RAI 3.5.2.3.10-1 requesting the applicant to state for the fiberglass and calcium silicate insulation components: state how the configuration of the jacketing ensures that it is properly installed so as to prevent water intrusion into the insulation; state the specific material types for any foamed plastic insulation material other than Rubatex; state the basis for why these materials are not subject to aging caused by direct exposure to sunlight UV; and state the specific materials of construction for the items associated with insulation jacketing, including insulation cement and the jacket components where the material type is not clear (i.e., integral vapor barrier, straps, bands, clamps, fasteners, breather springs, caulking and lagging adhesive); and state the basis for why these materials are not subject to aging caused by direct exposure to sunlight UV.

In its response, dated February 16, 2012, the applicant stated that the outdoor fiberglass and calcium silicate insulation jacketing is installed with interlocking joints along the length of the jacket and overlapping circumferential joints that are sealed and installed to be watertight, and the foamed plastic insulation material is sprayed-on polyurethane foam insulation on the external surface of the backup fire water storage tank installed with a coating that reduces the effect of direct UV exposure. Also, the applicant revised Table 3.5.2-10 to manage insulation degradation for foamed plastic (including Rubatex) by the Aboveground Metallic Tanks program. The outdoor jacketing material is aluminum, using either aluminum or galvanized steel straps, tie wire, bands, fasteners, breather springs, or clips. The aluminum jacketing is supplied with a factory-applied moisture proof barrier of epoxy coating or laminated polyethylene on the inside. The adhesive and insulating cement conforms to ASTM C449 and the caulking is a silicone rubber based compound. Further, most of the nonmetallic components are covered by the aluminum jacketing and thus not susceptible to degradation caused by UV exposure; however, some of the silicone rubber caulking may be exposed to UV. Therefore, the applicant revised Table 3.5.2-10 to manage the aging of this commodity group with the Structures Monitoring program.

The staff finds the applicant's response acceptable because (a) the outdoor fiberglass and calcium silicate insulation is covered with jacketing installed in such a manner as to preclude water intrusion, (b) the foamed plastic insulation and Rubatex components will be managed for degradation by the Aboveground Metallic Tanks program, which conducts visual inspections on a 2-year interval, (c) the insulation jacketing including insulation cement and the jacket components will be managed for degradation by the Structures Monitoring program, which conducts visual inspections on a 5-year interval, and (d) both the Aboveground Metallic Tanks and Structures Monitoring programs use visual inspections that are capable of detecting degradation of the components. The staff's concern described in RAI 3.5.2.3.2-10-1 is resolved.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.11 Primary Containment – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the primary containment component groups.

In LRA Table 3.5.2-11 the applicant stated that for concrete doors (reactor shield doors and plugs), concrete interior (diaphragm slab and pedestal), and steel components exposed to an encased in steel environment, there is no aging effect and no AMP proposed. The AMR items cite generic note G and plant-specific note 2. Plant-specific note 2 states that concrete or concrete (high density) or grout (high density) or Boron concrete encased in steel is protected from environments that promote age-related degradation. Concrete encased in steel has no aging effects.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable based on its review of ACI 201.1R and ACI 349.3R-02 which does not identify any durability issues associated with concrete in a steel environment. The staff notes that by being encased in steel, the components are protected from external environments and exhibit no aging effects requiring management for the period of extended operation.

In LRA Table 3.5.2-11 the applicant stated that for lead metal components (permanent drywell shielding) exposed to uncontrolled indoor air, there is no aging effect and no AMP is proposed. The AMR item cites generic note J and plant-specific note 4. Plant-specific note 4 states that lead shielding and fiberglass cloth have no applicable aging effects requiring management.

The staff reviewed the associated items in the LRA to confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable because there is no indication in the industry that lead exposed to an uncontrolled indoor air environment has any aging effects requiring management. The lack of historic negative operating experience indicates that lead is not likely to experience any degradation from uncontrolled indoor air. Therefore, based on industry experience and the assumption of proper design and application of the material, the staff finds that lead permanent drywell shielding plugs exposed to an uncontrolled indoor air environment exhibit no aging effects requiring management for the period of extended operation.

In LRA Table 3.5.2-11, the applicant stated that for fiberglass metal components (permanent drywell shielding) exposed to uncontrolled indoor air there is no aging effect and no AMP is proposed. The AMR item cites generic note J. This item cites plant-specific note 4 that states that lead shielding and fiberglass cloth have no applicable aging effects requiring management.

The staff reviewed the associated items in the LRA and could not confirm that no credible aging effects are applicable for this component, material, and environment combination. The staff lacked sufficient information to conclude that no aging management is required for these components because, given that the fiberglass material is located in the drywell, it is susceptible to high radiation levels. The staff noted that radiation can break down the molecule chains in the structure. By letter dated January 18, 2012, the staff issued RAI 3.5.2.3.11-1 requesting the applicant to state the composition of the matrix (e.g., polyester or vinyl ester) in which the glass fibers are set and state the basis for why there are no aging effects for this component, or state an AMP to manage the aging of the insulation components. In its response, dated February 16, 2012, the applicant stated that the permanent drywell shielding is a type of lead blanket encased in Alpha Maritex material, which is constructed from fiberglass fabric impregnated with silicone rubber. This material and blanket configuration was designed for the radiation environment in the drywell through the period of extended operation; however, the fiberglass fabric for the shielding blanket will be managed for rips and tears by the Structures Monitoring program. The applicant revised LRA Table 3.5.2-11 to add rips and tears as an AERM for this component and credited the Structures Monitoring program to manage the aging effect.

The staff finds the applicant's response acceptable because the applicant will age manage this material for rips and tears with the Structures Monitoring program, and the program's visual inspections are capable of detecting rips and tears. The staff's concern described in RAI 3.5.2.3.11-1 is resolved. However, LRA Section B.2.1.35, Structures Monitoring, program Description states, "Elastomers will be monitored for hardening, shrinkage and a loss of sealing" and does not address polymeric materials. In addition, Enhancement No. 2 lists newly added components. The staff noted that this enhancement was not updated to include fiberglass metal components (permanent drywell shielding). By letter dated April 5, 2012 the staff issued RAI 3.5.2.3.2-1.1 requesting the applicant to revise LRA Section B.2.1.35 to include polymeric materials being managed for rips and tears, and add fiberglass metal components (permanent drywell shielding) to Enhancement No. 2

In its response, dated April 13, 2012, the applicant stated that LRA Section A.2.1.35 and Enhancement No. 2 for the Structures Monitoring program were revised to include fiberglass metal components (permanent drywell shielding). In addition LRA Section B.2.1.35 was revised to state that fiberglass metal components (permanent drywell shielding) are monitored for rips and tears.

The staff finds the applicant's response acceptable because the Structures Monitoring program and Enhancement No. 2 were revised to include the component and its aging effect. The staff's concern described in RAI 3.5.2.3.2-1.1 is resolved.

In LRA Table 3.5.2-11, the applicant stated that Service Level 1 coatings exposed to treated water will be managed for loss of coating integrity by the Protective Coating Monitoring and Maintenance AMP. The AMR item cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of the GALL Report and

ASTM D 5163, which provides guidelines that are acceptable for establishing an inservice coatings monitoring program for Service Level 1 coating systems, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the Protective Coating Monitoring and Maintenance program is documented in SER Section 3.0.3.2.19. The staff finds the applicant's proposal to manage aging using the Protective Coating Monitoring and Maintenance Program acceptable because the applicant will be able to identify defective or deficient coatings and perform repairs in accordance with ASTM D 5163. In addition, degraded coating will be documented and summarized for further evaluation and trending, which is consistent with the GALL Report.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.12 Radwaste Enclosure – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-12, which summarizes the results of AMR evaluations for the radwaste enclosure component groups.

In LRA Table 3.5.2-12, the applicant stated that for lead penetration seals exposed to uncontrolled indoor air there is no aging effect and no AMP is proposed.

The staff reviewed the associated items in the LRA to confirm that no aging effects are applicable for this component, material, and environment combination. The staff finds the applicant's proposal acceptable because there is no indication in the industry that lead exposed to an uncontrolled indoor air environment has any aging effects requiring management. The lack of historic negative operating experience indicates that lead is not likely to experience any degradation from uncontrolled air indoor. Therefore, based on industry experience and the assumption of proper design and application of the material, the staff finds that lead penetration seals exposed to an uncontrolled indoor air environment exhibit no aging effects requiring management for the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.13 Reactor Enclosure – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-13, which summarizes the results of AMR evaluations for the reactor enclosure component groups.

In LRA Table 3.5.2-13, the applicant stated there is a TLAA for the loss of prestress aging effect of prestressed concrete exposed to an uncontrolled indoor air environment, which cites generic note H, and a plant-specific note, which states that "[t]he fuel pool girders are two interior concrete prestressed girders that are subject to loss of prestress, which is managed by a TLAA evaluated in Section 4.6.10."

The staff confirmed that there is a TLAA, as documented in LRA Section 4.6.10, for this component, material, and environment. The staff's evaluation of the TLAA for the prestressed fuel pool girders is documented in SER Section 4.6.10. The staff finds the applicant's proposal to manage aging using the TLAA acceptable because the applicant has demonstrated that the original analysis for the girder prestress remains valid for the period of extended operation.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.14 Service Water Pipe Tunnel – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-14, which summarizes the results of AMR evaluations for SW pipe tunnel component groups. The staff's review did not identify any items with notes F through J, indicating that the combinations of component type, material, environment, and AERM for this system are consistent with the GALL Report.

3.5.2.3.15 Spray Pond Pump House – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-15, which summarizes the results of AMR evaluations for the spray pond pump house component groups.

In LRA Table 3.5.2-15, the applicant stated that reinforced concrete pipe encasement, intake area slab, overflow structure, below grade (exterior, inaccessible) columns (spray network supports), foundation (inaccessible), and interior exposed to water flowing will be managed for cracking, loss of bond, and loss of material (spalling, scaling) by RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The AMR item cites generic note H.

The staff noted that this material and environment combination is identified in the GALL Report, which addresses reinforced concrete components exposed to water flowing and recommends GALL Report AMP XI.S6, "Structures Monitoring" program to manage aging effects. The applicant addressed the GALL Report identified aging effects for these component, material, and environment combinations in AMR items in LRA Table 3.5.2-15.

The staff's evaluation of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER 3.0.3.2.18. The staff noted that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program addresses age-related deterioration, degradation caused by environmental conditions, and the effects of natural phenomena that may affect the safety function of water-control structures. The staff also noted that the program will be used to manage loss of material, loss of preload, cracking, loss of bond, loss of material (spalling, scaling), increase in porosity and permeability, loss of strength, and loss of form in uncontrolled indoor air, outdoor air, raw water, water-standing, water flowing, groundwater, and soil environments. The staff further noted that the program is based on guidance provided in NRC RG 1.127 and ACI 349.3R-02 and that water-control structures will be monitored at a frequency not to exceed 5 years. The staff finds the applicant's proposal to manage aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program acceptable because the program will monitor the components in a water flowing environment for cracking, loss of bond, and loss of material (spalling, scaling) at a frequency not to exceed 5 years using guidance based on ACI 349.3R-02, acceptability of inaccessible areas will be evaluated when conditions exist in accessible areas that could indicate the presence of, or result in, degradation to such inaccessible areas, exposed portions of the below-grade concrete will be examined when excavated for any reason and water chemistry will be monitored at least 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.

In LRA Table 3.5.2-15, the applicant stated that for soil, rip-rap, sand, and gravel earthen water-control structures (emergency spillway), and embankments (dikes, include rock covered with shotcrete) exposed to outdoor air will be managed for loss of material and loss of form by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The AMR items cite generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of sample literature as for example that of the Department of Transportation "Bridge Scour and Stream Instability Countermeasures: Experience, Selection, and Design Guidance," 3rd Edition, publication dated September 2009 that identifies loss of material (loss of mass, mass wasting, erosion) and resulting loss of form as the aging mechanisms, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER 3.0.3.2.18. The staff noted that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program addresses age-related deterioration, degradation caused by environmental conditions, and the effects of natural phenomena that may affect the safety function of water-control structures. The staff also noted that the program will be used to manage loss of material, loss of preload, cracking, loss of bond, loss of material (spalling, scaling), increase in porosity and permeability, loss of strength, and loss of form in uncontrolled indoor air, outdoor air, raw water, water-standing, water-flowing, groundwater, and soil environments for earthen water-control structures (e.g., embankments and dikes). The staff further noted that the program is based on guidance provided in NRC RG 1.127 and ACI 349.3R-02 and water-control structures will be monitored at a frequency not to exceed 5 years. The staff finds the applicant's proposal to manage aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program acceptable because the program will monitor the earthen water-control structures and embankments in an outdoor air environment for loss of material and loss of form at a frequency not to exceed 5 years using guidance based on ACI 349.3R-02 (for example, see also "Guidelines for Inspection and Maintenance of Dams," CT Department of Environmental Protection, September 2001).

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.16 Turbine Enclosure – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the turbine enclosure component groups.

The staff's evaluation for PVC roofing scuppers exposed to outdoor air and cite generic note J, is documented in Section 3.5.2.3.2.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.2.3.17 Yard Facilities – Summary of Aging Management Evaluation

The staff reviewed LRA Table 3.5.2-11, which summarizes the results of AMR evaluations for the yard facilities component groups.

In LRA Table 3.5.2-17 the applicant stated that soil tank dikes exposed to outdoor air will be managed for loss of material and loss of form by the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program. The AMR item cites generic note G.

The staff reviewed the associated items in the LRA and considered whether the aging effects proposed by the applicant constitute all of the credible aging effects for this component, material, and environment description. Based on its review of sample literature as for example that of the Department of Transportation "Bridge Scour and Stream Instability Countermeasures: Experience, Selection, and Design Guidance," 3rd Edition, publication dated September 2009 that identifies loss of material (loss of mass, mass wasting, erosion) and resulting loss of form as the aging mechanisms, the staff finds that the applicant has identified all credible aging effects for this component, material, and environment combination.

The staff's evaluation of the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program is documented in SER 3.0.3.2.18. The staff noted that the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program addresses age-related deterioration, degradation caused by environmental conditions, and the effects of natural phenomena that may affect the safety function of water-control structures. The staff also noted that the program will be used to manage loss of material, loss of preload, cracking, loss of bond, loss of material (spalling, scaling), increase in porosity and permeability, loss of strength, and loss of form in uncontrolled indoor air, outdoor air, raw water, water-standing, water flowing, groundwater, and soil environments for earthen water-control structures (e.g., embankments and dikes). The staff further noted that the AMP is based on guidance provided in NRC RG 1.127 and ACI 349.3R-02 and water-control structures will be monitored at a frequency not to exceed 5 years. The staff finds the applicant's proposal to manage aging using the RG 1.127, Inspection of Water-Control Structures Associated with Nuclear Power Plants program acceptable because the AMP will monitor the soil tank dikes in an outdoor air environment for loss of material and loss of form at a frequency not to exceed

5 years using guidance based on ACI 349.3R-02 (for example, see also "Guidelines for Inspection and Maintenance of Dams," CT Department of Environmental Protection, September 2001).

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.5.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the structures and component supports within the scope of license renewal and subject to an AMR 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).

3.6 Aging Management of Electrical and Instrumentation and Controls System

This SER section documents the staff's review of the applicant's AMR results for the electrical and instrumentation and control (I&C) system components and component groups of:

- cable connections (metallic parts)
- electrical penetrations
- fuse holders
- high-voltage insulators
- insulation materials for electrical cables and connections
- metal enclosed bus
- switchyard bus and connections
- transmission conductors and connectors

3.6.1 Summary of Technical Information in the Application

LRA Section 3.6 provides AMR results for the electrical and I&C system components and component groups. LRA Table 3.6.1, "Summary of Aging Management Programs for the Electrical and I&C Components Evaluated in Chapter VI of NUREG-1801," is a summary comparison of the applicant's AMRs with those evaluated in the GALL Report for the electrical and I&C system components and component groups.

The applicant's AMRs evaluated and incorporated applicable plant-specific and industry operating experience in the determination of AERMs. The plant-specific evaluation included condition reports and discussions with appropriate site personnel to identify AERMs. The applicant's review of industry operating experience included a review of the GALL Report and operating experience issues identified since the issuance of the GALL Report.

3.6.2 Staff Evaluation

The staff reviewed LRA Section 3.6 to determine whether the applicant provided sufficient information to demonstrate that the effects of aging for the electrical and I&C system components within the scope of license renewal and subject to an AMR, 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 conducted an onsite audit of AMRs to ensure the applicant's claim that certain AMRs were consistent with the GALL Report. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluations of the AMPs are documented in SER Section 3.0.3. Details of the staff's audit evaluation are documented in SER Section 3.6.2.1.

In the onsite audit, the staff also selected AMRs consistent with the GALL Report and for which further evaluation is recommended. The staff confirmed that the applicant's further evaluations were consistent with the SRP-LR Section 3.6.2.2 acceptance criteria. The staff's audit evaluations are documented in SER Section 3.6.2.2.

The staff also conducted a technical review of the remaining AMRs not consistent with or not addressed in the GALL Report. The technical review evaluated whether all plausible aging effects have been identified and whether the aging effects listed were appropriate for the material-environment combinations specified. The staff's evaluations are documented in SER Section 3.6.2.3.

For SSCs the applicant claimed were not applicable or required no aging management, the staff reviewed the AMR items and the plant's operating experience to verify the applicant's claims.

Table 3.6-1 summarizes the staff's evaluation of components, aging effects or mechanisms, and AMPs listed in LRA Section 3.6 and addressed in the GALL Report.

Table 3.6-1 Staff Evaluation for Electrical and Instrumentation and Controls in the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Electrical equipment subject to 10 CFR 50.49 EQ requirements composed of Various polymeric and metallic materials exposed to Adverse localized environment caused by heat, radiation, oxygen, moisture, or voltage (3.6.1-1)	Various aging effects caused by various mechanisms in accordance with 10 CFR 50.49	EQ is a TLAA to be evaluated for the period of extended operation. See the Standard Review Plan, Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," for acceptable methods for meeting the requirements of 10 CFR 54.21(c)(1)(i) and (ii). See Chapter X.E1, "Environmental Qualification (EQ) of Electric Components," of this report for meeting the requirements of 10 CFR 54.21(c)(1)(iii).	Yes	TLAA	Consistent with the GALL Report (see SER Section 3.6.2.2.1)
High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air-outdoor (3.6.1-2)	Loss of material caused by mechanical wear caused by wind blowing on transmission conductors	A plant-specific aging management program is to be evaluated	Yes	NA	Not applicable to LGS (see SER Section 3.6.2.2.2)
High-voltage insulators composed of porcelain; malleable iron; aluminum; galvanized steel; cement exposed to air-outdoor (3.6.1-3)	Reduced insulation resistance caused by presence of salt deposits or surface contamination	A plant-specific aging management program is to be evaluated for plants located such that the potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution)	Yes	NA	Not applicable to LGS (see SER Section 3.6.2.2.2)
Transmission conductors composed of aluminum; steel exposed to air-outdoor (3.6.1-4)	Loss of conductor strength caused by corrosion	A plant-specific aging management program is to be evaluated for ACSR	Yes	NA	Not applicable to LGS (see SER Section 3.6.2.2.3)
Transmission connectors composed of aluminum; steel exposed to air-outdoor (3.6.1-5)	Increased resistance of connection caused by oxidation or loss of preload	A plant-specific aging management program is to be evaluated	Yes	NA	Not applicable to LGS (see SER Section 3.6.2.2.3)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Switchyard bus and connections composed of aluminum; copper; bronze; stainless steel; galvanized steel exposed to air-outdoor (3.6.1-6)	Loss of material caused by wind-induced abrasion; Increased resistance of connection caused by oxidation or loss of preload	A plant-specific aging management program is to be evaluated	Yes	NA	Not applicable to LGS (see SER Section 3.6.2.2.3)
Transmission conductors composed of aluminum; steel exposed to air-outdoor (3.6.1-7)	Loss of material caused by wind-induced abrasion	A plant-specific aging management program is to be evaluated for ACAR and ACSR	Yes	NA	Not applicable to LGS (see SER Section 3.6.2.2.3)
Insulation material for electrical cables and connections (including terminal blocks, fuse holders, etc.) composed of Various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to adverse localized environment caused by heat, radiation, or moisture (3.6.1-8)	Reduced insulation resistance caused by thermal/ thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Chapter XI.E1, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Insulation material for electrical cables and connections used in instrumentation circuits that are sensitive to reduction in conductor insulation resistance (IR) composed of Various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to Adverse localized environment caused by heat, radiation, or moisture (3.6.1-9)	Reduced insulation resistance caused by thermal/thermoxidative degradation of organics, radiolysis, and photolysis (UV sensitive materials only) of organics; radiation-induced oxidation; moisture intrusion	Chapter XI.E2, "Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits"	No	Insulation Material for Electrical Cables and Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements Used in Instrumentation Circuits	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Conductor insulation for inaccessible power cables greater than or equal to 400 volts (e.g., installed in conduit or direct buried) composed of various organic polymers (e.g., EPR, SR, EPDM, XLPE) exposed to adverse localized environment caused by significant moisture (3.6.1-10)	Reduced insulation resistance caused by moisture	Chapter XI.E3, "Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Inaccessible Power Cables Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Metal enclosed bus: enclosure assemblies composed of elastomers exposed to air-indoor, controlled or uncontrolled or air-outdoor (3.6.1-11)	Surface cracking, crazing, scuffing, dimensional change (e.g., "ballooning" and "necking"), shrinkage, discoloration, hardening and loss of strength caused by elastomer degradation	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.M38, "Inspection of Internal Surfaces in Miscellaneous Piping and Ducting Components"	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus: bus/connections composed of various metals used for electrical bus and connections exposed to air-indoor, controlled or uncontrolled or air-outdoor (3.6.1-12)	Increased resistance of connection caused by the loosening of bolts caused by thermal cycling and ohmic heating	Chapter XI.E4, "Metal Enclosed Bus"	No	Metal Enclosed Bus	Consistent with the GALL Report
Metal enclosed bus: insulation; insulators composed of porcelain; xenoy; thermo-plastic organic polymers exposed to air-indoor, controlled or uncontrolled or air-outdoor (3.6.1-13)	Reduced insulation resistance caused by thermal/thermoxidative degradation of organics/thermoplastics, radiation-induced oxidation, moisture/debris intrusion, and ohmic heating	Chapter XI.E4, "Metal Enclosed Bus"	No	Metal Enclosed Bus	Consistent with the GALL Report

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Metal enclosed bus: external surface of enclosure assemblies composed of steel exposed to air-indoor, uncontrolled or air-outdoor (3.6.1-14)	Loss of material caused by general, pitting, and crevice corrosion	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.S6, "Structures Monitoring"	No	Structures Monitoring	Consistent with the GALL Report
Metal enclosed bus: external surface of enclosure assemblies composed of galvanized steel; aluminum exposed to air-outdoor (3.6.1-15)	Loss of material caused by pitting and crevice corrosion	Chapter XI.E4, "Metal Enclosed Bus," or Chapter XI.S6, "Structures Monitoring"	No	NA	Not applicable to LGS (see SER Section 3.6.2.1.1)
Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air-indoor, uncontrolled (3.6.1-16)	Increased resistance of connection caused by chemical contamination, corrosion, and oxidation (in an air, indoor controlled environment, increased resistance of connection caused by chemical contamination, corrosion and oxidation do not apply); fatigue caused by ohmic heating, thermal cycling, electrical transients	Chapter XI.E5, "Fuse Holders"	No	Fuse Holders	Consistent with the GALL Report (see SER Section 3.6.2.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Fuse holders (not part of active equipment): metallic clamps composed of various metals used for electrical connections exposed to air-indoor, controlled or uncontrolled (3.6.1-17)	Increased resistance of connection caused by fatigue caused by frequent manipulation or vibration	Chapter XI.E5, "Fuse Holders" No aging management program is required for those applicants who can demonstrate these fuse holders are located in an environment that does not subject them to environmental aging mechanisms or fatigue caused by frequent manipulation or vibration	No	Fuse Holders	Consistent with the GALL Report (see SER Section 3.6.2.1)
Cable connections (metallic parts) composed of various metals used for electrical contacts exposed to air-indoor, controlled or uncontrolled or air-outdoor (3.6.1-18)	Increased resistance of connection caused by thermal cycling, ohmic heating, electrical transients, vibration, chemical contamination, corrosion, and oxidation	Chapter XI.E6, "Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements"	No	Electrical Cable Connections Not Subject to 10 CFR 50.49 Environmental Qualification Requirements	Consistent with the GALL Report
Connector contacts for electrical connectors exposed to borated water leakage composed of various metals used for electrical contacts exposed to air with borated water leakage (3.6.1-19)	Increased resistance of connection caused by corrosion of connector contact surfaces caused by intrusion of borated water	Chapter XI.M10, "Boric Acid Corrosion"	No	NA	Not applicable to BWRs (see SER Section 3.6.2.1.1)
Transmission conductors composed of aluminum exposed to air-outdoor (3.6.1-20)	Loss of conductor strength caused by corrosion	None - for Aluminum Conductor Aluminum Alloy Reinforced (ACAR)	None	NA	Not applicable to LGS (see SER Section 3.6.2.1.1)

Component Group (SRP-LR Item No.)	Aging Effect or Mechanism	AMP in SRP-LR	Further Evaluation in the GALL Report	AMP in LRA, Supplements, or Amendments	Staff Evaluation
Fuse holders (not part of active equipment): insulation material, metal enclosed bus: external surface of enclosure assemblies composed of insulation material: bakelite; phenolic melamine or ceramic; molded polycarbonate; other, galvanized steel; aluminum, steel exposed to air-indoor, controlled or uncontrolled (3.6.1-21)	None	None	NA - No AEM or AMP	NA	Consistent with the GALL Report

The staff's review of the electrical and I&C system component groups followed any one of several approaches. One approach, documented in SER Section 3.6.2.1, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and require no further evaluation. Another approach, documented in SER Section 3.6.2.2, reviewed AMR results for components that the applicant indicated are consistent with the GALL Report and for which further evaluation is recommended. A third approach, documented in SER Section 3.6.2.3, reviewed AMR results for components that the applicant indicated are not consistent with, or not addressed in, the GALL Report. The staff's review of AMPs credited to manage or monitor aging effects of the electrical and I&C system components is documented in SER Section 3.0.3.

3.6.2.1 AMR Results Consistent with the GALL Report

LRA Section 3.6.2.1 identifies the materials, environments, AERMs, and the following programs that manage aging effects for the electrical and I&C system components:

- insulation material for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements
- insulation material for electrical cables and connections not subject to 10 CFR 50.49 EQ requirements used in instrumentation circuits
- inaccessible power cables not subject to 10 CFR 50.49 EQ requirements
- electrical cable connections not subject to 10 CFR 50.49 EQ requirements
- metal enclosed bus
- structure monitoring
- fuse holders

LRA Table 3.6.2-1 summarizes AMRs for the electrical and I&C system components and indicate AMRs claimed to be consistent with the GALL Report.

The staff audited and reviewed the information in the LRA. The staff did not repeat its review of the matters described in the GALL Report; however, the staff did verify that the material presented in the LRA was applicable and that the applicant identified the appropriate GALL Report AMRs. The staff's evaluation follows.

In LRA Table 3.6.2-1, corresponding to Table 1 items 3.6.1.16 and 17, the applicant indicated, via Note A, that the combination of component type, material, environment, and AERM of fuse holders (not part of active equipment): metallic clamps is consistent with the GALL Report. The applicant provided information about how it will manage the aging effects by proposing the Fuse Holders program (B.2.1.42). The LRA claims that this program is consistent with GALL Report AMP XI.E5. During the onsite audit, the staff noted that certain fuse holders (metallic clamps) were in scope of license renewal (i.e., fuse holders in the switchyard control house) but were not included in the scope of Fuse Holders program. The GALL Report items VI.A.LP-23 and VI.A.LP-31, "Fuse Holders (Not Part of active equipment): Metallic Clamps," identifies the aging effect or aging mechanism as increased resistance of connection caused by chemical contamination, corrosion, oxidation; fatigue caused by ohmic heating, thermal cycling, electrical transients, increased resistance of connection caused by fatigue caused by frequent manipulation or vibration. The associated GALL Report AMP XI.E5, "Fuse Holders," states that fuse holders within the scope of license renewal should be tested to provide an indication of the condition of the metallic clamps of fuse holders.

The applicant did not provide technical justifications of why these fuse holders are excluded from the Fuse Holders program. By letter dated February 14, 2012 the staff issued RAI 3.6.2.3-1, requesting the applicant to provide a list of fuse holders within the scope of license renewal and subject to an AMR (i.e., fuse holders located outside of active equipment). For fuse holders within the scope of license renewal, the staff requested the applicant provide an evaluation that addressed each aging effect and mechanism identified in the GALL Report items VI.A.LP-23 and VI.A.LP-31 and identify fuse holders included in the Fuse Holder program and AMP basis document. In its response to RAI 3.6.2.3-1, provided by letter dated March 13, 2012, the applicant stated that the LGS metallic clamps of fuse holders, that are not part of an active assembly, were scoped and screened for AMR in accordance with the scoping and screening methodologies, documented in LRA Sections 2.1.1, 2.1.5, and 2.1.6. The applicant identified five electrical panels that contain fuse holders metallic clamps that are subject to an AMR:

- two drywell leak detection fuse panels – 12 fuse holders
- toxic chemical detection fuse panel – 6 fuse holders
- 500 kV substation battery fuse panel – 2 fuse holders
- 220 kV substation battery fuse panel – 2 fuse holders

Other LGS fuse holders that are not part of a larger assembly are for circuits that do not perform a license renewal intended function. The applicant also stated that the potential aging effects as discussed in the GALL Report items VI.A.LP-23 and VI.A.LP-31 are not applicable for the 500 kV substation battery fuse panel, the 220 kV substation battery fuse panel, and the toxic chemical detection fuse panels. The applicant's response to RAI 3.6.2.3-1 stated the following in relation to the aging effects for these fuse holders:

Chemical Contamination, Corrosion and Oxidation
These fuse holders are located in indoor, controlled environments that do not subject them to environmental aging mechanisms. The toxic chemical detection fuse panel is located in the plant's control enclosure in the upper fan room. The substation battery fuse panels are located in the substation control houses in the 500 kV and 220 kV substation yards. These panels and the enclosed fuse holders are located in indoor, controlled environments, are not subject to weather conditions and are, therefore, not subject to moisture from precipitation. Their indoor, controlled environment locations assure the fuse holders do not experience high relative humidity during normal conditions. A second barrier protecting the fuse holders from exposure to moisture is their location inside closed electrical boxes. The fuse holders are also protected from chemical contamination by their location inside closed electrical boxes. There are no sources of chemicals in the vicinity of the fuse boxes. Oxidation and corrosion are not a concern since the fuse holders are not located in or near humid areas, nor are they exposed to industrial or oceanic environments.

A walkdown of these electrical panels containing the in-scope fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation or corrosion.

Ohmic Heating, Thermal Cycling and Electrical Transients
Fuses for circuits that carry significant current in power applications could potentially be exposed to ohmic heating and thermal cycling. The fuse holders being evaluated are not in circuits that carry significant current in power applications. The fuses in the toxic chemical detection fuse panel provide 120Vac power to enclosure fans. These circuits are loaded with a small constant current. The substation battery fuse panels are for substation equipment direct current control power. The normal supply of power to loads is from the battery charger. The battery is normally on a float charge, thus the fuses are lightly loaded with a small constant current. Therefore, electrical and thermal cycling is not considered an applicable aging mechanism for these fuse holders. Mechanical stress caused by forces associated with electrical faults and transients are mitigated by the fast action of circuit protective devices at high currents. Also, mechanical stress caused by electrical faults is not considered a credible aging mechanism since such faults are infrequent and random in nature. The corrective action process is used to document adverse conditions and provides corrective actions associated with electrical faults and transients that cause the actuation of circuit protective devices.

Frequent Manipulation or Vibration
Wear and fatigue is caused by repeated removal and reinsertion of fuses. The fuses in these fuse holders are not subject to frequent manipulation (i.e., removal and reinsertion) because they are neither clearance nor isolation points which support periodic testing or preventative maintenance. Additionally, if fuses are manipulated for nonroutine inspection or maintenance, proceduralized good work practices would identify any abnormal condition such as loose or corroded fuse holders. These fuse holders are located in electrical panels that are not mounted on moving or rotating equipment such as motors, compressors, fans or pumps.

Because electrical panels are mounted with no attached sources of vibration, vibration is not an applicable aging mechanism. Therefore, these fuse holders will not exhibit aging effects from frequent manipulation or vibration.

The applicant also stated that potential aging effects as discussed in the GALL Report items VI.A.LP-23 and VI.A.LP-31 are applicable to the fuse holders for the drywell drain leak detection circuits. Therefore, these fuse holders are included in the Fuse Holders program. The applicant's response to RAI 3.6.2.3-1 also included a list of fuse holders that will be managed by the Fuse Holder program and stated that the Fuse Holders program basis document will be revised to identify these fuses in Element 1,"Scope of Program," in the Fuse Holders program basis document.

The staff finds the applicant response acceptable. The staff finds that fatigue, mechanical stress, vibration, chemical contamination, corrosion, and oxidation stressors are not applicable for fuse holders in the toxic chemical detection fuse panels, 500 kV substation battery fuse panel, nor the 220 kV substation battery fuse panel at LGS. Fatigue is an aging effect for plants that manipulate fuse to de-energize circuits for plant testing. The LGS fuses in these panels are not routinely pulled or manipulated for plant testing. Therefore, fatigue and mechanical stress are not applicable aging effect for these fuse panels. Ohmic heating and thermal cycling are for fuses that carry high current in power supply application or in heavy loading motors. The fuses installed in these panels are control circuits operating at low current that do not experience thermal cycling or ohmic heating. Therefore, the ohmic heating and thermal cycling are not applicable stressors for these fuse panels. Stresses associated with mechanical stress caused by electrical faults is not considered a creditable aging stressor since such faults are infrequent and the fuse design will interrupt the fault current in milliseconds. Forces associated with faults are mitigated by the fast action of fuse elements. Therefore, mechanical stress is not an applicable aging effect. Vibration is an applicable aging stressor for fuse holders that are mounted on moving equipment such as motors, compressors, and pumps. The fuses in these panels are not mounted on the equipment. They are mounted on a concrete wall or support structure that does not vibrate. Therefore, vibration is not an applicable stressor. Chemical contamination, corrosion, and oxidation are not aging stressors for fuse holders located in a controlled indoor air environment. Increased resistance of connection caused by chemical contamination, corrosion, and oxidation do not apply as indicated in the GALL Report item VI.A.LP-23. Furthermore, fuse holders are enclosed in a protective panel that would provide protection against chemical attack. The applicant has confirmed that there is no potential source of chemical contamination in the areas near the fuse holders. The applicant's walkdown for the electrical panels containing the in-scope fuse holders confirmed that the operating conditions for these fuse holders are clean and dry, with no evidence of moisture intrusion, chemical contamination, oxidation, or corrosion. Therefore, chemical contamination is not an applicable aging effect at LGS for the toxic chemical detection fuse panels, 500 kV substation battery fuse panel, or the 220 kV substation battery fuse panel.

The applicant has indicated that the potential aging effects as discussed in the GALL Report items VI.A.LP-23 and VI.A.LP-31 are applicable to the fuse holders for the drywell drain leak detection circuits. Therefore, these fuse holders are included in the Fuse Holder program. The applicant will manage these aging effects with the Fuse Holder program. The staff's evaluation of this program is in SER Section 3.0.3.1.23. The staff finds the proposed AMR acceptable because as discussed above, the applicant has identified the proper aging effects for fuse holders within the scope of license renewal and subject to an AMR. Also, the Fuse Holder program will detect the increased resistance of connection of the fuse holder metallic clamp caused by aging effects using thermography and/or resistance measurement. The testing of the fuse holders is consistent with that in GALL Report AMP XI.E5. The applicant will revise the Fuse Holders program basis document to identify these fuses in Element 1, "Scope of Program," in the Fuse Holders program-basis document. Therefore, the staff's concern as described in RAI 3.6.2.3-1 is resolved.

3.6.2.1.1 AMR Results Identified as Not Applicable

In LRA Table 3.6.1, item 3.6.1-15 under metal enclosed bus: external surface of enclosed assemblies composed of galvanized steel, aluminum exposed to outdoor air, the applicant states that there is no galvanized steel or aluminum in metal enclosed bus exposed to outdoor air that are in scope of license renewal. During the onsite audit, the staff did not identify metal enclosed bus enclosure assemblies composed of galvanized steel or aluminum exposed to air-outdoor within the scope of license renewal. Therefore, the staff determined that no AMR is required for galvanized steel or aluminum enclosure assemblies at LGS.

In LRA Table 3.6.1, item 3.6.1-20 under transmission conductor composed of aluminum exposed to outdoor air, the applicant states that there are no aluminum transmission conductors exposed to air-outdoor that are in scope of license renewal at LGS. The staff noted that loss of conductor strength caused by corrosion is not applicable to aluminum conductor aluminum alloy reinforced (ACAR) transmission conductors. LGS does not have ACAR transmission conductors, it has aluminum conductor steel reinforced (ACSR) transmission conductors. ACAR transmission conductors are, therefore, not applicable to LGS. The AMR for ACSR transmission conductors is addressed in SER Section 3.6.2.2.3. The staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

For LRA Table 3.6.1 item 3.6.1-19, the applicant claimed that the corresponding AMR items in the GALL Report are not applicable because the associated items are only applicable to PWRs. The staff reviewed the SRP-LR, confirmed these items only apply to PWRs, and finds these items are not applicable to LGS.

3.6.2.1.2 Conclusion

The staff evaluated the GALL Report AMR items that the applicant claimed were not applicable. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed were not applicable, are not applicable to LGS Units 1 and 2.

As discussed in SER Section 3.0.2.2, for those AMRs that the applicant claimed consistency with the GALL Report, the staff evaluated the applicant's claim of consistency. The staff also reviewed information pertaining to the applicant's consideration of recent operating experience and proposals for managing aging effects. On the basis of its review, the staff concludes that the AMR results, which the applicant claimed to be consistent with the GALL Report, are consistent.

Therefore, the staff concludes that the applicant has demonstrated that the effects of aging for these components will be adequately managed so that their intended function(s) will be maintained consistent with the CLB during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2 AMR Results Consistent with the GALL Report for Which Further Evaluation is Recommended

In LRA Section 3.6.2.2, the applicant further evaluates aging management, as recommended by the GALL Report, for the electrical and I&C system components and provides information concerning how it will manage the following aging effects:

- electrical equipment subject to EQ
- reduced insulation resistance caused by presence of any salt deposits and surface contamination, and loss of material caused by mechanical wear caused by wind blowing on transmission conductors
- loss of material caused by wind-induced abrasion and fatigue, loss of conductor strength caused by corrosion, and increased resistance of connection caused by oxidation or loss of preload
- QA for aging management of nonsafety-related components

For component groups evaluated in the GALL Report, for which the applicant claimed consistency with the report and for which the report recommends further evaluation, the staff audited and reviewed the applicant's evaluation to determine whether it adequately addressed the issues further evaluated. In addition, the staff reviewed the applicant's further evaluations against the criteria contained in SRP-LR Section 3.6.2.2.The staff's review of the applicant's further evaluation follows.

3.6.2.2.1 Electrical Equipment Subject to Environmental Qualification

LRA Section 3.6.2.2.1 is associated with LRA Table 3.6.1 item 3.6.1-1. The applicant stated that Environmental Qualification is a TLAA as defined in 10 CFR 54.3. TLAAs are required to be evaluated in accordance with 10 CFR 54.21(c)(1). The applicant also stated that evaluation of this TLAA is addressed separately in Section 4.4, "Environmental Qualification (EQ) of Electrical Equipment," of this LRA. SER Section 4.4 documents the staff's review of the applicant's evaluation of this TLAA and the EQ electrical component program.

3.6.2.2.2 Reduced Insulation Resistance Caused by Presence of Any Salt Deposits and Surface Contamination, and Loss of Material Caused by Mechanical Wear

LRA Section 3.6.2.2.2 is associated with LRA Table 3.6.1, items 3.6.1-2 and 3.6.1-3 and addresses reduced insulation resistance caused by presence of salt deposits and surface contamination, and loss of material caused by mechanical wear. The applicant stated that LGS is not located near the seacoast. It is located inland in southeastern Pennsylvania.

The applicant also stated that LGS is located in an area where industrial airborne particle concentrations are comparatively low, since it is located in a suburban area with no heavy industry nearby. Minor contamination is washed away by rainfall or snow, and cumulative build up has not been experienced and is not expected to occur. Based on LGS's location and confirmed by its operating experience, surface contamination is not a significant aging effect for LGS. The applicant then concluded that aging management activities for surface contamination from dust, salt, and industrial effluents are not required for the period of extended operation.

Regarding loss of material caused by mechanical wear, the applicant stated that wind loading that can cause a transmission line and insulators to sway is considered in the design and installation. Although rare, surface rust of the metallic cap may form where galvanizing is burnt off caused by flashover from lightning strikes. Surface rust is not a significant concern and would not cause a loss of intended function if left unmanaged for the period of extended operation. The applicant also stated that wear and surface rust have not been identified during routine switchyard inspections. Based on LGS's design and confirmed by its operating experience, mechanical wear caused by wind blowing on transmission conductors is not significant enough to cause a loss of intended function. The applicant then concluded that aging management activities for loss of material caused by mechanical wear is not required for the period of extended operation.

The staff reviewed LRA Section 3.6.2.2.2 against the criteria in SRP-LR Section 3.6.2.2.2, which states that reduced insulation resistance caused by salt deposits and surface contamination may occur in high-voltage insulators. The SRP-LR recommends further evaluation of plant-specific AMPs for plants at locations of potential salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Loss of material caused by mechanical wear caused by wind on transmission conductors may occur in high-voltage insulators. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that these aging effects are adequately managed.

The staff noted that SRP-LR Section 3.6.2.2.2 states that a plant-specific AMP may be required for management of reduced insulation resistance caused by presence of salt deposits and surface contamination for plants located such that potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution). Since LGS is not located in the vicinity of salt water bodies or industrial pollution, surface contamination of high-voltage insulator is not a concern. In addition, rainfall and snow periodically wash away contamination; the glazed insulator surface also aids this contamination removal. The plant-specific operating experience at LGS supports the applicant's conclusion that contamination is not significant at LGS because the applicant has indicated that there has been no occurrence of insulator flashover caused by dust.

The staff also notes that EPRI (License Renewal Handbook, Revision 1, February 2007) states that mechanical wear in insulators is an aging effect for strain and suspension insulators in that they are subject to movement. Movement of insulators can be caused by wind blowing the supported transmission conductor, causing it to swing from side to side. If this swing is frequent enough, it could cause wear in the metal contact point of the insulator string and between an insulator and supporting hardware. Although this mechanism is possible, industry operating experience has shown that the transmission conductors do not normally swing and that even when they do, caused by a substantial wind, do not continue to swing for a long period of time once the wind has subsided. Transmission conductors are designed and installed not to swing significantly and cause wear caused by wind induced abrasion and fatigue. Transmission conductors within the scope of license renewal are typically short spans (connecting the switchyard to the startup transformers) and the surface area exposed to wind loads are not significant. Furthermore, the applicant has not identified any instances of loss of material on high-voltage insulators caused by mechanical wear. Based on its review, the staff finds that mechanical wear aging effect of high-voltage insulators is not an AERM at LGS.

Based on the evaluations above, the staff concludes that the applicant has met the SRP-LR Section 3.6.2.2.2 criteria. For those items that apply to LRA Section 3.6.2.2.2, the staff finds that that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.3 Loss of Material Due to Wind-Induced Abrasion and Fatigue, Loss of Conductor Strength Due to Corrosion, and Increased Resistance of Connection Due to Oxidation or Loss of Preload

LRA Section 3.6.2.2.3 is associated with LRA Table 3.6.1, items 3.6.1-4, 3.6.1-5, 3.6.1-6, and 3.6.1-7 addressing loss of material caused by wind-induced abrasion and fatigue, loss of conductor strength caused by corrosion, and increased resistance of connections caused by oxidation or loss of preload of transmission conductors and connections, and switchyard bus and connections. The applicant stated that transmission conductor vibration or sway could be caused by wind loading. Industry experience has shown that the transmission conductors do not normally swing significantly. When transmission conductors do swing caused by a substantial wind, they do not continue to swing for very long once the wind has subsided. The applicant also stated that wind loading that can cause a transmission line to vibrate or sway is considered in design and installation. The applicant then concluded that the loss of material aging effect that could result from wind-induced transmission conductor vibration or sway is not applicable and would not cause a loss of intended function for transmission conductors for the period of extended operation.

The applicant also stated that the in scope transmission conductors at LGS are a tie line between the 500 kV and 220 kV substations. These conductors are 1590 MCM 54/19 aluminum conductor steel reinforced (ACSR). Each phase has two conductors. The 1590 MCM 54/19 ACSR transmission conductor is a large, substantial transmission conductor. It is approximately 1.5 inches in diameter and is configured with 19 steel conductors wrapped by 54 aluminum conductors. The rated or ultimate strength per ASTM standards and National Electric Safety Code (NESC) heavy load tension requirements of 1590 MCM ACSR are 54500 lbs and 19075 lbs, respectively.

The applicant stated that the PECO Transmission and Distribution design practices follow the NESC methodologies. The NESC requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also states the maximum tension of a conductor must be designed to withstand heavy load requirements, which include consideration of ice, wind, and temperature. The most prevalent contribution to loss of conductor strength of an ACSR transmission conductor is corrosion, which includes corrosion of the steel core and aluminum strand pitting. For ACSR conductors, degradation begins as a loss of zinc from the galvanized steel core wires. Corrosion rates depend largely on air quality, which includes suspended particles chemistry, sulfur dioxide concentration in air, precipitation, fog chemistry, and meteorological conditions.

The applicant stated that tests performed by Ontario Hydroelectric showed a 30 percent loss of composite conductor strength of an 80-year-old ACSR conductor caused by corrosion. The LGS in scope transmission conductors are the same type of transmission conductors evaluated in the Ontario Hydroelectric study and in the analysis of the Ontario Hydroelectric Study and in the EPRI License Renewal Electrical Handbook.

The applicant stated that LGS is located in an area where industrial airborne particle concentrations are comparatively low, since it is located in a suburban area with no heavy industry nearby. In the Ontario Hydroelectric Study, the conductors most affected by atmospheric corrosion were located in areas subject to pollution sources and a major urban area. Therefore, the environmental impact to the LGS transmission conductors (which are located in a suburban area) is bounded by the Ontario Hydroelectric conductors (which are located in polluted and urban environments).

The applicant stated that assuming a 30 percent loss of strength as demonstrated by the Ontario Hydroelectric tests, there would still be significant margin between what is required by the NESC and actual conductor strength. The margin between the NESC heavy load and the ultimate strength is 35,425 lbs; i.e., there is a 65 percent ultimate strength margin. The applicant also stated that the Ontario Hydroelectric study showed a 30 percent loss of composite conductor strength in an 80-year-old conductor. In the case of the 1590 MCM ACSR transmission conductors, a 30 percent loss of ultimate strength would mean that there would still be a 35 percent ultimate strength margin between what is required by the NESC and the actual conductor strength. The applicant further stated that in conclusion, the in scope LGS transmission conductors are bounded by the Ontario Hydroelectric study by test methodology, design and construction, and environment. The applicant then concluded that the above evaluations demonstrate with reasonable assurance that transmission conductors will have ample strength margin through the period of extended operation.

The applicant stated that good bolting practices are employed for transmission connectors. The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued at the time of installation to avoid loss of preload. The applicant also stated that the transmission connectors are designed and installed using lock washers and stainless steel Belleville washers (not electroplated) that provide vibration absorption and prevent loss of preload. The applicant then concluded that oxidation and loss of preload are not applicable aging mechanisms at LGS.

The applicant stated that switchyard buses are connected to flexible conductors that do not normally vibrate and are supported by insulators and ultimately by static, structural components such as concrete footings and structural steel. Switchyard bus is rigidly mounted and is, therefore, not subject to abrasion induced by wind loading. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue is not applicable to LGS switchyard bus. The applicant also stated that good bolting practices are employed for switchyard bus connections. The connections are treated with corrosion inhibitors to avoid connection oxidation and torqued at the time of installation to avoid loss of preload. The switchyard bus bolted connections are designed and installed using lock washers and stainless steel Belleville washers (not electroplated) that provide vibration absorption and prevent loss of preload. The applicant then concluded that oxidation and loss of preload are not applicable aging mechanisms at LGS.

The staff reviewed LRA Section 3.6.2.2.3 against the criteria in SRP-LR Section 3.6.2.2.3, which states that loss of material caused by wind induced abrasion and fatigue, loss of conductor strength caused by corrosion, and increased resistance of connection caused by oxidation or loss of preload could occur in transmission conductors and connections, and in switchyard bus and connections. The GALL Report recommends further evaluation of a plant-specific AMP to ensure that this aging effect is adequately managed.

The staff noted switchyard buses are connected to flexible conductors that do not swing and are supported by insulators and structural supports such as concrete footings and structural steel. Since there are no connections to moving or vibrating equipment, wind-induced abrasion and fatigue is not an applicable aging mechanism for switchyard bus and connections at LGS.

The staff noted that wind born particulates have not been shown to be a contributor to loss of material at LGS and wind fatigue is addressed in 3.6.2.2.2. Therefore, the staff finds that wind induced abrasion and fatigue is not a significant AERM for transmission conductors and connections at LGS.

The staff noted that design of switchyard bolted connections precludes torque relaxation. The use of stainless steel Belleville washers is the industry standard to preclude torque relaxation. LGS design incorporates the use of stainless steel Belleville washers on bolted electrical connections to compensate for temperature changes, maintain the proper torque, and prevent loosening. This method of assembly is consistent with the good bolting practices recommended by industry guidelines (EPRI TR-104213, "Bolted Joint Maintenance & Application Guide"). Based on the review, the staff finds that loosing of the switchyard bolted connections is not an AERM at LGS.

The bolted connections and washers at LGS are coated with an antioxidant compound (electrical joint compound) before tightening the connection to prevent the formation of oxides on the metal surface and to prevent moisture from entering the connection, thus reducing the chances of corrosion. The staff finds that increased resistance of connection caused by oxidation or loss of preload are not significant aging effects requiring management for transmission conductor and switchyard bus connections at LGS.

The Ontario Hydro study showed about 30 percent loss of conductor strength of an 80-year- old ACSR conductor caused by corrosion. In addition, the National Electrical Safety Code (NESC) requires that tension on installed conductors be a maximum of 60 percent of the ultimate conductor strength. The NESC also sets the maximum tension a conductor must be designed to withstand under heavy load requirements, which include consideration of ½ inch of radial ice and 4 pounds per square feet (psf) wind. The staff reviewed these requirements concerning the specific conductors included in the AMR at LGS. Based on the Ontario Hydro study, a loss of conductor strength of 30 percent on ACSR transmission conductors would mean that the conductor strength would be 38150 lbs (54,500 lbs x 0.7 = 38,150 lbs). The ratio between the heavy loading and the ultimate conductor strength would be approximately 50 percent (19,075 lbs/38,150 lbs). The NESC requires that tension on installed conductor be a maximum of 60 percent of the ultimate conductor strength. The tension (heavy load) of a typical transmission conductor as illustrated by the applicant would not exceed the NESC maximum requirement of 60 percent of the ultimate conductor strength. The staff determined that with a 30 percent loss of conductor strength, there is still ample margin between the NESC requirements and the actual conductor strength. Therefore, the staff finds that loss of conductor strength caused by corrosion is not a significant AERM at LGS.

Based on the evaluations above, the staff concludes that the applicant has met the SRP-LR Section 3.6.2.2.3 criteria. For those items that apply to LRA Section 3.6.2.2.3, the staff finds that the LRA is consistent with the GALL Report and 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 during the period of extended operation, as required by 10 CFR 54.21(a)(3).

3.6.2.2.4 Quality Assurance for Aging Management of Nonsafety-Related Components

SER Section 3.0.4 documents the staff's evaluation of the applicant's QA program.

3.6.2.3 AMR Results Not Consistent with or Not Addressed in the GALL Report

In LRA Table 3.6.2-1, the staff reviewed additional details of the AMR results for material, environment, AERM, and AMP combinations not consistent with or not addressed in the GALL Report.

In LRA Table 3.6.2-1, the applicant, via notes F through J, indicated that the combination of component type, material, environment, and AERM does not correspond to an item in the GALL Report. The applicant provided further information about how it will manage the aging effects. Specifically, note F indicates that the material for the AMR item component is not evaluated in the GALL Report. Note G indicates that the environment for the AMR item component and material is not evaluated in the GALL Report. Note H indicates that the aging effect for the AMR item component, material, and environment combination is not evaluated in the GALL Report. Note I indicates that the aging effect identified in the GALL Report for the item component, material, and environment combination is not applicable. Note J indicates that neither the component nor the material and environment combination for the item is evaluated in the GALL Report.

For component type, material, and environment combinations not evaluated in the GALL Report, the staff reviewed the applicant's evaluation to determine whether 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. The staff's evaluation is documented in the following sections.

3.6.2.3.1 Electrical Commodities – Summary of Aging Management Evaluation – LRA Table 3.6.2-1

The staff reviewed LRA Table 3.6.2-1, which summarizes the results of AMR evaluations for the electrical commodities component groups.

In LRA Table 3.6.2-1, the applicant stated that no aging effect is expected, and, therefore, no AMP is credited for managing cement, metal and porcelain high-voltage insulators exposed to outdoor air. The applicant cited generic note I indicating that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. The LRA relates the component to GALL Report items VI.A.LP-32 and LRA Table 3.6.1, item 3.6.1-2 both of which identify loss of material caused by mechanical wear caused by wind blowing on transmission conductors as an applicable aging effect for porcelain, malleable iron, aluminum, galvanized steel, and cement high-voltage insulators exposed outdoor air. The GALL Report item states that a plant-specific program is to be evaluated.

Plant-specific note 1 states that, based on LGS design and operating experience, loss of material is not an applicable aging effect for LGS high-voltage insulators.

The staff's evaluation of cement, metal, and porcelain high-voltage insulators exposed to outdoor air with a potential aging effect of loss of material caused by mechanical wear caused by wind blowing on transmission conductors is documented in SER Section 3.6.2.2.2. The staff agrees, based on its evaluation, that the aging effect of loss of material caused by mechanical wear caused by wind blowing on transmission conductors is not applicable to LGS cement, metal, and porcelain high-voltage insulators exposed to outdoor air.

In LRA Table 3.6.2-1, the applicant stated that no aging effect is expected, and, therefore, no AMP is credited for managing cement, metal and porcelain high-voltage insulators exposed to outdoor air. The applicant cited generic note I indicating that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. The LRA relates the component to GALL Report item VI.A.LP-28 and LRA Table 3.6.1 item 3.6.1-3, both of which identify reduced insulation resistance caused by the presence of salt deposits or surface contamination as an applicable aging effect for porcelain, malleable iron, aluminum, galvanized steel, and cement high-voltage insulators exposed outdoor air. GALL Report item VI.A.LP-28 and LRA Table 3.6.1 item 3.6.1-3, both state that a plant-specific program is to be evaluated for plants located such that the potential exists for salt deposits or surface contamination (e.g., in the vicinity of salt water bodies or industrial pollution).

The LRA also cites plant-specific note 2 which states that based on LGS design and operating experience, reduced insulation is not an applicable aging effect for LGS high-voltage insulators.

The staff's evaluation of cement, metal, and porcelain high-voltage insulators exposed to outdoor air with a potential aging effect of reduced insulation resistance caused by the presence of salt deposits or surface contamination is documented in SER Section 3.6.2.2.2. The staff agrees, based on its evaluation, that the aging effect of reduced insulation resistance caused by the presence of salt deposits or surface contamination is not applicable to LGS cement, metal, and porcelain high-voltage insulators exposed to outdoor air.

In LRA Table 3.6.2-1, the applicant stated that no aging effect is expected, and, therefore, no AMP is credited for managing aluminum and stainless steel switchyard bus and connections exposed externally to outdoor air. The applicant cited generic note I indicating that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. The LRA relates the component to GALL Report item VI.A.LP-39 and LRA Table 3.6.1 item 3.6.1-6, both of which identify loss of material caused by wind-induced abrasion and increased resistance of connection caused by oxidation or loss of preload as applicable aging effects for aluminum, copper, bronze, stainless steel, and galvanized switchyard bus and connections exposed outdoor air. GALL Report item VI.A.LP-39 and LRA Table 3.6.1 item 3.6.1-6, both state that a plant-specific program is to be evaluated.

The LRA also cites plant-specific note 3 which states that based on LGS design and operating experience, loss of material and increased resistance of connection are not applicable aging effects for LGS switchyard bus and connections.

The staff's evaluation of aluminum and stainless steel switchyard bus and connections exposed externally to outdoor air with a potential aging effect of loss of material caused by wind-induced abrasion and increased resistance of connection caused by oxidation or loss of preload is documented in SER Section 3.6.2.2.3. The staff agrees, based on its evaluation, that the aging effects of loss of material caused by wind-induced abrasion and increased resistance of connection caused by oxidation or loss of preload is not applicable to LGS aluminum and stainless steel switchyard bus and connections exposed externally to outdoor air.

In LRA Table 3.6.2-1, the applicant stated that no aging effect is expected, and, therefore, no AMP is credited for managing aluminum and steel transmission conductors exposed externally to outdoor air. The applicant cited generic note I indicating that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. The LRA relates the component to GALL Report item VI.A.LP-47 and LRA Table 3.6.1 item 3.6.1-7, both of which identify loss of material caused by wind-induced abrasion as an applicable aging effect for aluminum and steel transmission conductors exposed outdoor air. GALL Report item VI.A.LP-47 and LRA Table 3.6.1 item 3.6.1-7, both state that a plant-specific program is to be evaluated for ACAR and ACSR.

The LRA also cites plant-specific note 4 which states that based on LGS design and operating experience, loss of material is not applicable aging effects for LGS transmission conductors.

The staff's evaluation of aluminum and steel transmission conductors exposed externally to outdoor air with a potential aging effect of loss of material caused by wind-induced abrasion is documented in SER Section 3.6.2.2.3. The staff agrees, based on its evaluation, that the aging effect of loss of material caused by wind-induced abrasion is not applicable to LGS aluminum and steel switchyard transmission conductors exposed externally to outdoor air.

In LRA Table 3.6.2-1, the applicant stated that no aging effect is expected, and, therefore, no AMP is credited for managing aluminum and steel transmission conductors exposed externally to outdoor air. The applicant cited generic note I indicating that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. The LRA relates the component to GALL Report item VI.A.LP-38 and LRA Table 3.6.1 item 3.6.1-4, both of which identify loss of conductor strength caused by corrosion as an applicable aging effect for aluminum and steel transmission conductors exposed outdoor air. GALL Report item VI.A.LP-38 and LRA Table 3.6-1 item 3.6.1-4, both state that a plant-specific program is to be evaluated for ACSR.

The LRA also cites plant-specific note 5, which states that based on LGS design and operating experience, loss of conductor strength is not applicable aging effects for LGS transmission conductors.

The staff's evaluation of aluminum and steel transmission conductors exposed externally to outdoor air with a potential aging effect of loss of conductor strength caused by corrosion is documented in SER Section 3.6.2.2.3. The staff agrees, based on its evaluation, that the aging effect of loss of conductor strength caused by corrosion is not applicable to LGS aluminum and steel switchyard transmission conductors exposed externally to outdoor air.

In LRA Table 3.6.2-1, the applicant stated that no aging effect is expected, and, therefore, no AMP is credited for managing stainless steel transmission conductors exposed externally to outdoor air. The applicant cited generic note I indicating that the aging effect in the GALL Report for this component, material, and environment combination is not applicable. The LRA relates the component to GALL Report item VI.A.LP-48 and LRA Table 3.6.1 item 3.6.1-5, both of which identify increased resistance of connection caused by oxidation or loss of preload as an applicable aging effect for aluminum and steel transmission conductors exposed to outdoor air. GALL Report item VI.A.LP-38 and LRA Table 3.6.1 item 3.6.1-5, both state that a plant-specific program is to be evaluated.

The LRA also cites plant-specific note 6 which states that based on LGS design and operating experience, increased resistance of connection is not an applicable aging effect for LGS transmission conductors.

The staff's evaluation of stainless steel transmission conductors exposed externally to outdoor air with a potential aging effect of increased resistance of connection caused by oxidation or loss of preload is documented in SER Section 3.6.2.2.3. The staff agrees that, based on its evaluation, the aging effect of increased resistance of connection caused by oxidation or loss of preload is not applicable to LGS stainless steel transmission conductors exposed externally to outdoor air.

On the basis of its review, the staff finds that the applicant has appropriately evaluated the AMR results of material, environment, AERM, and AMP combinations not evaluated in the GALL Report. The staff finds 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).

3.6.3 Conclusion

The staff concludes that the applicant has provided sufficient information to demonstrate that the effects of aging for the electrical and I&C components within the scope of license renewal and subject to an AMR 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).

3.7 Conclusion for Aging Management Review Results

The staff reviewed the information in LRA Section 3, "Aging Management Review Results," and LRA Appendix B, "Aging Management Programs and Activities." On the basis of its review of the AMR results and AMPs, the staff concludes, with the exception of Open Items 3.0.3.2.13-1 and 3.0.5-1, that the applicant has demonstrated that the aging effects 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 applicable UFSAR supplement program summaries and concludes that the supplement adequately describes the AMPs credited for managing aging, as required by 10 CFR 54.21(d).

With regard to these matters, the staff concludes, with the exception of Open Item 3.0.3.2.13-1, that there is reasonable assurance that the applicant will continue to conduct the activities authorized by the renewed licenses in accordance with the CLB, and any changes made to the CLB, in order to comply with 10 CFR 54.21(a)(3), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 4

TIME-LIMITED AGING ANALYSES

4.1 Identification of Time-Limited Aging Analyses

This safety evaluation report (SER) section provides the United States Nuclear Regulatory Commission's (NRC's, the staff) evaluation of the applicant's basis provided by Exelon Generation Company, LLC (Exelon or the applicant) for identifying those plant-specific or generic analyses that need to be identified as time-limited aging analyses (TLAAs) for the applicant's license renewal application (LRA) and the list of TLAAs for the LRA. TLAAs are certain plant-specific analyses that involve time-limited assumptions defined by the current operating term. This SER section also provides the staff's evaluation of the applicant's basis for identifying those exemptions that need to be identified in the LRA pursuant to 54.21(c)(2).

Pursuant to the requirements in Title 10 of the *Code of Federal Regulations* (10 CFR) 54.21(c)(1), an applicant for license renewal must list all evaluations, analyses, and calculations in the current licensing basis (CLB) that conform to the definition of a TLAA, as defined in 10 CFR 54.3, which states that a plant-specific or generic evaluation, analysis, or calculation is a TLAA if it meets all six of the following TLAA identification criteria:

(1) involve a system, structure, or component (SCC) within the scope of license renewal application, as delineated in 10 CFR 54.4(a)

(2) consider the effects of aging

(3) involve time-limited assumptions defined by the current operating term (e.g., 40 years)

(4) were determined to be relevant by the applicant in making a safety determination

(5) involve conclusions or provide the basis for conclusions related to the capability of the SSC to perform its intended functions, as described in 10 CFR 54.4(b)

(6) are contained or incorporated by reference in the CLB

For each evaluation, analysis, or calculation the applicant shall demonstrate one of the following:

(1) the analyses remain valid for the period of extended operation

(2) the analyses have been projected to the end of the period of extended operation

(3) the effects of aging on the intended function(s) will be adequately managed during the period of extended operation

In addition, 10 CFR 54.21(c)(2) requires applicants to list all plant-specific exemptions granted in accordance with the exemption approval criteria in 10 CFR 50.12 and that are based on a TLAA. For any such exemptions, the applicant must evaluate and justify the continuation of the exemptions for the period of extended operation.

The staff's guidance recommendations for reviewing LRA Chapter 4.1 sections are given in NUREG-1800, Revision 2, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants" (SRP-LR), Section 4.1.

4.1.1 Summary of Technical Information in the Application

4.1.1.1 Identification of TLAAs

LRA Section 4.1 states that the applicant reviewed and evaluated the evaluations, analyses, and calculations in the CLB against the six criteria for TLAAs in 10 CFR 54.3. The LRA also states that the applicant reviewed the list of TLAAs in the SRP-LR to see if they are applicable to and included as part of the applicant's CLB.

The applicant stated that its review of the CLB included the following plant-specific or generic sources (documents or records): (1) Updated Final Safety Analysis Report (UFSAR); (2) Technical Specifications; (3) NRC Safety Evaluation Reports for the original operating licenses; (4) NRC Safety Evaluations (SEs) applicable to its CLB; (5) docketed licensing correspondence; (6) vendor-issued, NRC-sponsored, and licensee topical reports; (7) design calculations; (8) Code stress reports or Code design reports; and (9) plant drawings and specifications.

The applicant provided its list of TLAAs in LRA Table 4.1-2, and indicates that the following evaluations, analyses, or calculations in the CLB meet the six criteria for TLAAs in 10 CFR 54.3 and are TLAAs for the LRA:

- reactor pressure vessel (RPV) neutron embrittlement in LRA Section 4.2
- metal fatigue in LRA Section 4.3
- environmental qualification of electrical components in LRA Section 4.4
- containment liner and penetrations fatigue analysis in LRA Section 4.5
- plant-specific TLAAs in LRA Section 4.6

The applicant provided its bases for dispositioning these TLAAs in accordance with the requirements in either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of LRA Sections 4.2 – 4.6.

The applicant indicated that the following generic evaluations, analyses, or calculations listed in SRP-LR Table 4.1-2 are not part of its CLB; therefore, the LRA does not need to include these generic categories of TLAAs as applicable TLAAs for the LRA:

- concrete containment tendon prestress
- inservice local metal containment corrosion analyses

The applicant also indicates potentially applicable plant-specific evaluations, analyses, or calculations listed in SRP-LR Table 4.1-3 that are not part of its CLB; therefore, the LRA does not need to include these categories of TLAAs:

- intergranular separation of reactor vessel low-alloy steel under austenitic stainless steel cladding

- low-temperature overpressure protection (LTOP) analysis
- fatigue analysis for reactor coolant pump (RCP) flywheel
- flow-induced vibration endurance limit analyses for reactor vessel internals (RVI)
- fatigue analysis for main steam supply lines to a steam-driven auxiliary feedwater pump
- leak-before-break (LBB) analyses
- metal corrosion allowance analyses
- inservice inspection flaw growth analyses for a 40-year period

4.1.1.2 Identification of Regulatory Exemptions

The applicant stated that its review of the CLB identified two exemptions based on a TLAA, but neither of these exemptions is required for the period of extended operation. The exemptions were associated with pressure-temperature (P-T) limits developed using exemptions to Appendix G of 10 CFR Part 50 to permit use of American Society of Mechanical Engineers (ASME) Code Cases N-588 and N-640. Since the current P-T limits are only valid for 32 effective full-power years (EFPY), the LRA states that they must be superseded before the period of extended operation. Therefore, the current exemptions will not be required during the period of extended operation.

4.1.2 Staff Evaluation

4.1.2.1 Identification of TLAAs

The staff reviewed the applicant's methodology for identifying the TLAAs and the results for the LRA against the six criteria for TLAA identification in 10 CFR 54.3 and the generic list of TLAAs in SRP-LR Section 4.1, including those in SRP-LR Tables 4.1-2 and 4.1-3 as applicable to its CLB. The staff used the review procedures in SRP-LR Section 4.1.3 as the basis for its review.

4.1.2.1.1 Evaluations, Analyses, and Calculations in the CLB Conforming to 10 CFR 54.3 TLAA Criteria

The staff confirmed that the applicant included its TLAAs for the RPV neutron irradiation embrittlement analyses in the applicable referenced subsections of LRA Section 4.2, which includes the TLAAs for the upper-shelf energy (USE) assessment, adjusted reference temperature (ART), P-T limits assessment, reactor vessel (RV) circumferential weld inspection, RV axial weld inspection, and RV core reflood thermal shock analysis. The staff confirmed that these analyses conform to all six of the criteria for identifying TLAAs in 10 CFR 54.3. Thus, the staff noted that the applicant's identification of these TLAAs was in conformance with the staff recommendations in SRP-LR Sections 4.1 and 4.2, which provide the bases for identifying these types of neutron irradiation embrittlement analyses as TLAAs in accordance with the requirements in 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of these analyses as TLAAs is acceptable because it is in compliance with 10 CFR 54.21(c)(1). The staff evaluates the applicant's basis for dispositioning each of these TLAAs in accordance with either 10 CFR 54.21(c)(1)(ii) or (iii) in the applicable subsections of SER Section 4.2.

The staff confirmed that the applicant included its TLAAs on metal fatigue analyses in the applicable subsections of LRA Section 4.3. The staff confirmed that these analyses conform to all six of the criteria for identifying TLAAs in 10 CFR 54.3. Thus, the staff noted that the applicant's identification of these TLAAs was in conformance with the staff recommendations in SRP-LR Sections 4.1 and 4.3, which provide the bases for identifying these types of fatigue analyses as TLAAs in accordance with the requirements in 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of these analyses as TLAAs is acceptable because it is in compliance with 10 CFR 54.21(c)(1). The staff evaluates the applicant's basis for dispositioning each of these TLAAs in accordance with either 10 CFR 54.21(c)(1)(i) or (iii) in the applicable subsections of SER Section 4.3.

The staff noted that the applicant addressed the effects of the reactor coolant environment on component fatigue life, consistent with the guidance in the SRP-LR and the staff's recommendations for resolving Generic Safety Issue (GSI) No. 190, dated December 26, 1999. The staff's evaluation of the applicant's environmentally assisted fatigue (EAF) calculations for limiting reactor coolant pressure boundary (RCPB) components is given in SER Section 4.3.3.

The staff confirmed that the applicant included its TLAA on environmental qualification (EQ) of electrical equipment in LRA Section 4.4. The staff confirmed that the analysis conforms to all six of the criteria for identifying TLAAs in 10 CFR 54.3. Thus, the staff confirmed that the applicant's identification of the EQ TLAA was in conformance with the staff recommendations in SRP-LR Sections 4.1 and 4.4, which provide the bases for identifying EQ analyses as TLAAs in accordance with 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of the EQ TLAA is acceptable because it is in compliance with 10 CFR 54.21(c)(1). The staff evaluates the applicant's basis for dispositioning the EQ analysis in accordance with 10 CFR 54.21(c)(1)(iii) in SER Section 4.4.

The staff confirmed that the applicant included its TLAAs on fatigue analyses for the containment liner and penetrations in LRA Section 4.5. The staff confirmed that the analyses conform to the six criteria for TLAAs in 10 CFR 54.3. Thus, the staff noted that the applicant's identification of these TLAAs was in conformance with the staff recommendations in SRP-LR Sections 4.1 and 4.6, which provide the staff's bases for identifying containment structure analyses as TLAAs in accordance with 10 CFR 54.21(c)(1). Based on this review, the staff finds that the identification of these containment component TLAAs is acceptable because it is in compliance with 10 CFR 54.21(c)(1). The staff evaluates the applicant's basis for dispositioning these TLAAs in accordance with 10 CFR 54.21(c)(1)(iii) in SER Sections 4.5.

The staff confirmed that the applicant included the following plant-specific TLAAs for the LRA in the LRA Section 4.6: (1) reactor enclosure crane cyclic loading analysis (LRA Section 4.6.1), (2) emergency diesel generator (EDG) enclosure cranes cyclic loading analysis (LRA Section 4.6.2), (3) RPV core plate rim hold-down bolt loss of preload (LRA Section 4.6.3), (4) main steam line flow restrictors erosion analysis (LRA Section 4.6.4), (5) jet pump auxiliary spring wedge assembly (LRA Section 4.6.5), (6) jet pump restrainer bracket pad repair clamps (LRA Section 4.6.6), (7) refueling bellows and support cyclic loading analysis (LRA Section 4.6.7), (8) downcomers and main steam relief valve (MSRV) discharge piping fatigue analyses (LRA Section 4.6.8);and (9) jet pump slip joint repair clamps (LRA Section 4.6.9). The staff noted that the applicant's identification of these TLAAs was in conformance with the staff recommendations for identifying plant-specific TLAAs in SRP-LR Sections 4.1 and 4.7.

Based on this review, the staff finds that the identification of these plant-specific TLAAs is acceptable because it is in compliance with 10 CFR 54.21(c)(1). The staff evaluates the applicant's basis for dispositioning these plant-specific TLAAs in accordance with either 10 CFR 54.21(c)(1)(i), (ii), or (iii) in the applicable subsections of SER Section 4.6.

4.1.2.1.2 Staff Evaluation of Applicant's List of Evaluations, Analyses, and Calculations in the CLB That Do Not Conform to Six Criteria for TLAAs in 10 CFR 54.3 and the Absence of Generic or Potentially Applicable Plant-Specific TLAAs caused by Absence in the CLB

Main Steam Isolation Valves Metal Fatigue TLAA. UFSAR Section 5.4.5.2, states that the design objective for the main steam isolation valve (MSIV) is a minimum of 40 years' service at the specified operating conditions. Operating cycles (excluding exercise cycles) are estimated to be 50 cycles per year during the first year and 20 cycles per each year thereafter. The staff noted that the MSIV analysis performed was based on a specific number of operating cycles. However, the applicant did not identify this analysis as a TLAA in the LRA. By letter dated January 31, 2012, the staff issued RAI 4.1-1 requesting the applicant to justify why the MSIV analysis performed based on operating cycles need not be identified as a TLAA in accordance with 10 CFR 54.21(c)(1).

In its response dated February 29, 2012, the applicant stated that the MSIV fatigue analysis is a TLAA identified and evaluated in LRA Section 4.3.1 for ASME Code, Section III, Class 1 valves. The staff noted that LRA Section 4.3.1 describes the applicant's disposition of the metal fatigue TLAA for ASME Code Section III, Class 1 components including Class 1 valves. The staff's evaluation of the applicant's TLAA disposition is documented in SER Section 4.3.1.2. The applicant also stated that operating cycles described in UFSAR Section 5.4.5.2 are included in the thermal and pressure cycles evaluated in the MSIV ASME Code Section III, Class 1 fatigue analysis. The applicant stated that the MSIV fatigue analysis is based on the transients listed in UFSAR Section 3.9.1.1.8, "Main Steam Isolation Valve Transients." The staff noted that one of those transients in UFSAR Section 3.9.1.1.8 is "Preop @ 100 F/hr" with a limit of 150 cycles and this transient was not included in LRA Tables 4.3.1-1 and 4.3.1-2. Therefore, it was not clear to the staff whether this transient is monitored or needs to be monitored during the period of extended operation. By letter dated April 17, 2012, the staff issued followup RAI 4.1-1.1 requesting the applicant to clarify if this transient is associated with a transient already monitored by the Fatigue Monitoring program.

In its response dated May 4, 2012, the applicant stated that the "Preop at 100°F/hr" thermal transient, referenced in UFSAR Section 3.9.1.1.8, is not monitored by the Fatigue Monitoring program. The applicant explained that the MSIVs were designed in accordance with the 1968 Draft ASME Code for Pumps and Valves for Nuclear Power. The Draft ASME Code required the manufacturer to verify the adequacy of the valve for its expected cyclic loading conditions by computing a thermal cyclic index, I_t, with a limit of 1.0. The applicant explained that the design specifications for the MSIVs describe this transient as "Preoperational and Periodic Inservice Testing" with a total 150 cycles, but Section 454.1.d in the Draft ASME Code allows the transient to be excluded from the consideration in these cyclic duty evaluations. The applicant stated that, therefore, the transient did not contribute to the I_t values calculated for the MSIVs. The staff noted that since this transient was not included in the determination of the I_t value in the design calculation, the transient is not required to be monitored by the Fatigue Monitoring program.

The staff finds the applicant's responses to RAI 4.1-1 and followup RAI 4.1-1.1 acceptable because the applicant clarified that the TLAA disposition of the MSIV is documented in LRA Section 4.3.1 and the "Preop at 100 F/hr" transient was not used in determining the I_t value for the MSIV; thus, the Fatigue Monitoring program can be used, without monitoring this transient, to ensure the TLAA remains valid. The staff's concerns identified in RAI 4.1-1 and followup RAI 4.1-1.1 are resolved.

Absence of a Concrete Containment Tendon Prestress TLAA. In LRA Table 4.1-2, the applicant identified that the Limerick Generating Station (LGS), Units 1 and 2, CLBs do not include a containment tendon pre-stress analysis. The applicant stated that its containment design does not include tendons.

SRP-LR Table 4.1-2 identifies the containment tendon pre-stress analysis as a generic type of TLAA that may be generically applicable to an applicant's plant design. SRP-LR Section 4.5 provides the staff's recommended criteria for accepting these type of TLAAs in accordance with the TLAA acceptance requirements in 10 CFR 54.21(c)(1)(i), (ii), or (iii). The relevant SRP-LR recommendations are only applicable to concrete containment structures that use pre-stressed tendons as the containment structure reinforcement basis.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "*absence of a TLAA*" basis. The staff confirmed, from its review of UFSAR Section 3.8.1, that the containment is a concrete structure reinforced with rebar and, therefore, it does not use pre-stressed tendons as the basis for reinforcing the containment mat, cylinder, or dome. Therefore, the staff concludes that the LRA does not need to include a concrete containment pre-stress TLAA because it has confirmed that the containment does not include pre-stressed tendons as the containment reinforcement basis. Thus, it is not contained in or incorporated by reference in the LGS Units 1 and 2 CLBs (Criterion 6 of 10 CFR 54.3(a)).

Absence of an Inservice Localized Metal Containment Corrosion TLAA. In LRA Table 4.1-2, the applicant identified that the LGS Units 1 and 2 CLBs do not include any inservice local metal containment corrosion analyses for the containment structure. SRP-LR Table 4.1-2 identifies a local metal containment corrosion analysis as a generic type of TLAA that may be generically applicable to an applicant's plant design.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "*absence of a TLAA*" basis. The staff confirmed that UFSAR Section 3.8 indicates that the containment is a reinforced concrete containment design. The staff also confirmed that UFSAR Section 3.8 does not reference any localized metal corrosion analyses for the containment structure, other Seismic Category 1 structures, or their subcomponents. Therefore, the staff concludes that the LRA does not need to include any localized metal containment corrosion TLAAs because it has confirmed that the applicant's CLB does not include any metal corrosion analyses for the concrete containment structure, other Seismic Category 1 structures, or their subcomponents. Thus, localized metal corrosion analyses are not contained in or incorporated by reference in the LGS Units 1 and 2 CLBs (Criterion 6 of 10 CFR 54.3(a)).

Absence of a TLAA for Managing Growth of Intergranular Separation of Reactor Vessel Low-Alloy Steel under Austenitic Stainless Steel Cladding. In LRA Table 4.1-2, the applicant identified that the CLB does not include any cycle-dependent analysis in evaluation of intergranular separations (underclad cracks or underclad cracking) in RPV cladding-to-forging welds.

SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific RPV underclad cracking analysis that qualifies as a TLAA for the applicant's LRA. The relevant SRP-LR recommendations are only applicable to pressurized-water reactor (PWR) or boiling water reactor (BWR) designs that include RPV SA-508, Class 2 forgings that were welded to the RPV cladding using an uncontrolled high-heat input weld process. The SRP-LR guidance does not apply if the CLB confirms that the design of the shell, head, or nozzle portions of the RPV does not include such forging components, or if it can be demonstrated that the heat input used to fabricate the applicable SA-508 Class 2 forging-to-cladding welds was appropriately controlled during the weld fabrication process. The NRC Regulatory Guide (RG) 1.43 provides the recommended criteria for meeting these weld process heat input controls.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "*absence of a TLAA*" basis. The staff noted that UFSAR Section 5.3.1.2 identifies that the RPVs are fabricated primarily from high-strength, low-alloy steel plates and forgings. UFSAR Section 5.3.1.2 also indicates that the low-alloy steel RPV plates were ordered to SA-533, Grade B, Class 1 specifications and the forgings were ordered to ASME SA-508 Class 2. RG 1.43 identified that underclad cracking has been observed for SA-508 Class 2 forging and plates made to coarse grain practice. UFSAR Section 5.3.1.4.1.3 indicates that the cracking discussed in RG 1.43 is not applicable to its RPV because its vessel plate and nozzle forgings are made to fine grain practice. Furthermore, UFSAR Section 5.2.3.3.2.4 indicates that its welding of cladding to low-alloy steel forgings is made with a low-heat input process. The staff also noted that, in accordance with RG 1.43, such a low-heat input process minimizes heating to the base metal and that cracking was not observed in SA-508 Class 2 materials clad by a low-heat input process.

Based on its review, the staff concludes that the generic RV underclad cracking analysis listed in SRP-LR Table 4.1-3 is not a TLAA for LGS Units 1 and 2. This analysis is not a TLAA in accordance with 10 CFR 54.21(c)(1) because the staff has confirmed that LGS Units 1 and 2 RV designs do not include SA-508 Class 2 or 3 forging shells or forging nozzles with cladding welded to the vessel using a high-heat input welding process. Thus, the RV underclad cracking analysis is not contained in or incorporated by reference in the LGS Units 1 and 2 CLBs (Criterion 6 of 10 CFR 54.3(a)).

<u>Absence of a Low-Temperature Overpressure Protection TLAA</u>. In LRA Table 4.1-2, the applicant identified that the Units 1 and 2 CLBs do not include a LTOP analysis for the RPV and RCPB.

SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific LTOP analysis that qualifies as a TLAA. The SRP-LR recommendations are only applicable to the LTOP systems in PWRs. The SRP-LR guidance is not applicable to BWRs because BWRs do not include LTOP systems.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "*absence of a TLAA*" basis. The staff noted that Chapter 1 of the UFSAR defines the reactors as a General Electric (GE)-designed BWR built to the BWR-4 model specifications. The staff also confirmed that the BWR-4 model does not include an LTOP system. Therefore, the staff concludes that the LRA does not need to include a plant-specific LTOP TLAA because the staff has confirmed that the applicant's reactor design does not have an LTOP system. Thus, the LTOP analysis is not contained in or incorporated by reference in the LGS Units 1 and 2 CLBs (Criterion 6 of 10 CFR 54.3(a)).

Absence of a TLAA for Main Steam Supply Lines to a Steam-Driven Auxiliary Feedwater Pump. In LRA Table 4.1-2, the applicant identified that the LGS Units 1 and 2 CLBs include fatigue analyses for main steam supply lines to turbine-driven HPCI pumps and RCIC pump.

SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific metal fatigue analysis for auxiliary feedwater (AFW) pump main steam supply lines that qualifies as a TLAA. The SRP-LR recommendations are only applicable to PWRs that include steam-driven AFW pumps. The SRP-LR guidance is not applicable to BWRs because BWRs are not designed with AFW pumps.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "*absence of a TLAA*" basis. The staff noted that Chapter 1 of the UFSAR defines the reactors as a GE-designed BWR built to the BWR-4 model specifications. The staff also confirmed that the BWR-4 model does not include AFW systems or pumps. Therefore, the staff concludes that the LRA does not need to include a plant-specific TLAA for steam-driven AFW pump steam supply lines because it has confirmed that the applicant's reactor design does not have AFW systems or pumps. The staff's review of the fatigue analyses for the main steam supply lines to the HPCI and RCIC pumps are documented in SER Section 4.3.1.2. Thus, the fatigue analysis for main steam lines that supply steam to steam-driven AFW pumps is not contained in or incorporated by reference in the LGS Units 1 and 2 CLBs (Criterion 6 of 10 CFR 54.3(a)).

Absence of a Flaw Growth TLAA for Reactor Coolant Pump Flywheels. In LRA Table 4.1-2, the applicant identified that the CLB does not include any cycle dependent flaw growth or flaw tolerance, for RCP flywheels. SRP-LR Table 4.1-3 identifies that that CLB may include a plant-specific cycle-dependent fatigue or flaw tolerance analysis for RCP flywheels that qualifies as a TLAA. The SRP-LR recommendations are only applicable to RCP flywheels in PWR designs. The SRP-LR guidance is not applicable to a BWR because the analogous pump components in BWR designs (i.e., the recirculation pumps) are not designed with flywheels.

The staff reviewed the information in the UFSAR for relevancy to the applicant's "*absence of a TLAA*" basis. The staff noted that Chapter 1 of the UFSAR defines the reactors as a GE-designed BWR built to the BWR-4 model specifications. The staff also confirmed that the BWR-4 model does not include an RCP flywheel. Therefore, the staff concludes that the LRA does not need to include a plant-specific TLAA for RCP flywheels because it has confirmed that the applicant's reactor design does not have RCP flywheels. Thus, the flaw growth analysis for RCP flywheels is not contained in or incorporated by reference in the LGS Units 1 and 2 CLBs (Criterion 6 of 10 CFR 54.3(a)).

Absence of a Flow-Induced Vibration Endurance Limit Analyses for RVI Components. SRP-LR Table 4.1-3 identifies "Flow-Induced Vibration (FIV) Endurance Limit for the Reactor Vessel Internals" as an analysis that may be generically applicable to an applicant's CLB.

UFSAR Section 3.9.2.4 indicates that the reactor internals were tested consistent with the provisions of RG 1.20, Revision 2, "Comprehensive Vibration Assessment Program for Reactor Internals During Preoperational and Initial Startup Testing," for nonprototype Category I plants. The test procedure required operating the recirculation system at the rated flow, with internals installed, followed by inspection for evidence of vibration, wear, or loose parts. The test duration was sufficient to subject critical components to at least 10^6 cycles of vibration during two-loop and single-loop operation of the recirculation system. UFSAR Section 3.9.2.3 also states that the major reactor internal components within the vessel were subjected to extensive testing coupled with dynamic systems analyses to properly describe the resulting FIV phenomena incurred from normal operation and from anticipated operational transients. The staff noted that the stresses associated with the high-cycle FIV analyses for the RVI components would permit the components to withstand an extremely high number (more than 10^6 cycles) of low stress cycles beyond the number of vibratory cycles associated with the end of the period of extended operation, and the analyses would not conform to the TLAA Criterion 3 in 10 CFR 54.3(a), that the analyses does not involve time-dependent parameters defined by the life of the plant (e.g., 40 years).

The staff noted that the applicant received a 5-percent stretch power uprate (SPU) by an amendment dated January 24, 1996, for LGS Unit 1 and February 16, 1995, for LGS Unit 2. In its SPU amendment request, the applicant indicated that the stretch power uprate did not have an impact on the FIV loads assumed for the design of the RV internals. The staff reviewed the SPU SE and noted that Section 3.2.3 of the SE concluded that the 5 percent SPU would have little or no effect on the FIV assumptions for the RV internals because the uprated conditions did not create any change to the maximum allowable core flow.

The staff also noted that the applicant received a 1.65-percent measurement uncertainty recapture (MUR) power uprate by an amendment dated April 3, 2011, for LGS Units 1 and 2. In its MUR amendment request, the applicant indicated that the MUR uprate also did not have an impact on the FIV loads assumed for the design of the RV internals. The staff reviewed the SE for the MUR amendment approval and noted that Section 3.5.2 of the SE concluded that the 1.65-percent MUR power uprate would have little or no effect on the FIV assumptions for the RV internals because the maximum licensed core flow is unchanged. The staff also noted that the SE did not identify a need to include assessment of any age-related degradation caused by FIV of the RV internal components under SPU and MUR loads.

Based on this review, the staff concludes that the RV internals FIV endurance limit analyses do not meet the definition of TLAAs because the analyses do not involve time-limited assumptions defined by the current operating term (Criterion 3 of 10 CFR 54.3(a)).

<u>Absence of a Leak-Before-Break TLAA</u>. In LRA Table 4.1-2, the applicant identified that its review of the LGS Units 1 and 2 CLBs did not identify any LBB analysis for the RCPB piping. SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific time-dependent LBB analysis for the RCPB that qualifies as a TLAA. The staff noted that the relevant SRP-LR recommendations are only applicable to LBB analyses requested for high-energy piping systems in PWR RCPB designs and approved by the staff for relaxation from "*Dynamic Effect*" analysis requirements in 10 CFR Part 50, Appendix A, General Design Criterion (GDC) 4. The staff noted that the relevant SRP-LR guidance is not applicable to BWR designs because the staff has not approved any LBB analysis methodologies for analogous high-energy piping in BWR RCPB designs. The staff reviewed the information in the UFSAR and confirmed that the applicant's design basis does not include or make reference to any LBB analysis requested and approved for relaxation from the dynamic effect analysis requirements in 10 CFR Part 50, Appendix A, GDC 4.

Based on its review, the staff concludes that the LRA does not need to include a plant-specific LBB TLAA because it has confirmed that the LGS Units 1 and 2 CLBs do not include any LBB analyses. Thus, a LBB analysis is not contained or incorporated by reference in the applicant's CLB (Criterion 6 of 10 CFR 54.3(a)).

Absence of Plant-Specific Metal Corrosion Allowance TLAAs. In LRA Table 4.1-2, the applicant identified that the LGS Units 1 and 2 CLBs do not include any time-dependent metal corrosion allowance evaluations for metallic components that would need to be identified as TLAAs for the LRA. SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific metal component corrosion allowance analysis that qualify as TLAAs.

The staff considered additional documents, such as NRC generic communications and ASME Code requirements, which could incorporate a requirement for a corrosion allowance TLAA. The staff reviewed the information in the UFSAR for relevance to the applicant's "*absence of a TLAA*" basis and noted that, in UFSAR Table 3.9-6(g), the applicant identified that the calculation of the minimum wall thickness for nozzles on the main steam safety/relief valves included a corrosion allowance of the components. The staff also noted that, in UFSAR Table 3.9-6(h), the applicant identified a corrosion allowance of a 0.12-inch minimum that was added to minimum wall thickness for the MSIVs. The staff noted that in UFSAR Section 5.2.3.2.3, the applicant states that conservative corrosion allowances were included in the design of carbon steel and alloy steel reactor coolant system (RCS) components to protect them from general corrosion as a result of exposure to the reactor coolant environment. The staff noted that the corrosion allowances, specified in the initial design of these components as an input, were not based on any time-dependent analyses.

Based on its review, the staff concludes that the LRA does not need to include a plant-specific metal corrosion allowance TLAA because it has confirmed that the applicant's design does not have a time-dependent assessment for metal corrosion (Criterion 3 of 10 CFR 54.3(a)).

Absence of Inservice Inspection Flaw Growth Analyses Defined by a 40-Year Period. In LRA Table 4.1-2, the applicant identified that the LGS Units 1 and 2 CLBs do not include any time-dependent inservice inspection flaw growth, flaw tolerance, or fracture mechanics evaluations for ASME Code Class components that demonstrate structural stability over a 40-year period. SRP-LR Table 4.1-3 identifies that the CLB may include a plant-specific inservice inspection fatigue flaw growth or time-dependent flaw tolerance analyses that qualify as TLAAs.

During the review of the LRA, the staff confirmed that the CLB did not include any inservice inspection-based flaw evaluations defined by a 40-year licensing period, with the exception of the applicant's flaw evaluation for a vessel nozzle-to-safe end weld identified below.

In Appendix C to the LRA, as amended by letter dated February 15, 2012, the applicant provided responses to applicant action items (AAIs) to all applicable Boiling Water Reactor Vessel and Internals Project (BWRVIP) reports credited for aging management. In particular, AAI No. 14 for BWRVIP-74-A "BWR Reactor Vessel Inspection and Flaw Evaluation Guidelines," states:

> Components that have indications that have been previously analytically evaluated in accordance with subsection IWB-3600 of Section XI to the ASME

Code until the end of the 40-year service period shall be re-evaluated for the 60-year service period corresponding to the LR term.

The UFSAR supplement contains a commitment (Commitment No. 47) to address BWRVIP-74-A, AAI No. 14. Commitment No. 47 states that the flaw in LGS Unit 1 RPV nozzle to safe-end weld VRR-1RD-1A-N2H will be re-evaluated in accordance with ASME Code, Section XI, Subsection IWB-3600, for the 60-year service period. The staff noted that BWRVIP-74-A is referenced by the BWR Vessel Internals program and the staff's evaluation of the applicant's program is documented in SER Section 3.0.3.2.2. The staff also noted that the response did not include a justification of why such analyses were not identified as TLAAs in accordance with 10 CFR 54.21(c)(1). By letter dated March 9, 2012, the staff issued RAI 4.1-2 requesting the applicant to justify whether or not the flaw evaluations should be identified as TLAA for the LRA.

In its response dated March 20, 2012, the applicant stated that a flaw was identified in the, LGS, Unit 1 RPV nozzle-to-safe end weld VRR-1RD-1A-N2H (N2H) in 1989 during an ultrasonic test examination. Three evaluations of the flaw in the N2H safe end were performed in accordance with ASME Code Section XI, Subsection IWB-3600, before the use of the mechanical stress improvement process (MSIP) repair process in 1992. The applicant stated that the first two evaluations were performed to justify that it was acceptable for continued service for one additional operating cycle and they do not conform to the definition of a TLAA. The applicant also stated that the third evaluation was submitted to the staff by letter dated April 3, 1992, for the application of MSIP. The applicant stated in the April 3, 1992, letter that an evaluation to verify the stability of the crack was performed based on ASME Code, Section XI, Subsection, IWB-3642. The applicant further stated that this evaluation and the application of MSIP are not TLAAs because they do not involve time-limited assumptions defined by the current operating term (Criterion 3 of 10 CFR 54.3(a)). The staff reviewed the information in the April 3, 1992, letter and confirmed that the evaluation of the compressive stress zone generated by the MSIP and the magnitude of the compressive stress do not involve a time-dependent parameter. The staff also confirmed that the provision in ASME Code, Section XI, IWB-3642, which relies on the safety margin based on load for normal, emergency, and faulted operating conditions, do not involve any time-dependent parameter.

Based on its review, the staff found the applicant's response to RAI 4.1-2 acceptable because the applicant clarified that the flaw evaluations performed for the MSIP application do not involve time-limited assumptions defined by the current operating term (Criterion 3 of 10 CFR 54.3(a)). Therefore, the staff concluded that the applicant does not need to include a plant-specific TLAA for the flaw tolerance evaluations for the RPV nozzle-to-safe end weld VRR-1RD-1A-N2H (N2H).

Based on its review, the staff concludes that the LRA does not need to include a plant-specific TLAA for inservice inspection flaw analysis because it has confirmed that the LGS Units 1 and 2 CLBs do not include any inservice inspection flaw analyses with time-dependent assumption. Thus, inservice inspection flaw analyses are not contained or incorporated by reference in the applicant's CLB (Criterion 6 of 10 CFR 54.3(a)).

<u>Potentially Applicable TLAAs in Response to BWRVIP Report AAIs</u>. The LRA references several BWRVIP reports, which have been reviewed and approved by the staff, as part of its aging management programs (AMPs) for the reactor vessel and its internal components. As

part of the staff's approval of these BWRVIP reports, the staff's SEs on the reports included a number of AAIs that were to be addressed by license renewal applicants as part of the basis for applying the reports to the CLB. BWR applicants applying for license renewal were requested to include their responses to the AAIs in their LRAs. The staff noted that the LRA did not include the applicant's responses to the AAIs associated with these BWRVIP reports. By letter dated January 17, 2012, the staff issued RAI BWRVIP-1 requesting the applicant to submit the necessary information for each AAI in the BWRVIP reports that are applicable to the LGS CLB.

In its response, dated February 15, 2012, the applicant amended the LRA to include a new Appendix C that addressed each of the applicable AAIs. The applicant stated that it identified a need to provide a new license renewal commitment for BWRVIP-74-A, "BWR Reactor Pressure Vessel Inspection and Flaw Evaluation Guidelines," relative to AAI No. 14. The staff noted that the applicant's BWR Vessel Internals program credits BWRVIP-74-A. The staff's review of AAI No. 14 on BWRVIP-74-A is documented in SER Section 3.0.3.2.2.

The staff noted that the applicant also provided responses to AAIs for the following BWRVIP reports in LRA Appendix C:

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

Based on its review, the staff found that the applicant resolved the issue identified in RAI BWRVIP-1 because the applicant amended the LRA to include its responses to each of the AAIs currently applicable to the LGS Units 1 and 2 CLBs. The staff's evaluations of the applicant's responses to the AAIs that relate to TLAAs are provided in the following subsections.

TLAA-Related AAIs that are Generically Applicable to Multiple BWRVIP Reports. The staff noted that AAI No. 2 is generically applicable to the aforementioned BWRVIP reports listed above. AAI No. 2 requests that LR applicants referencing the applicable BWRVIP reports ensure that the programs and activities specified as necessary in the applicable BWRVIP report are summarily described in the UFSAR supplement, including the evaluation of TLAAs for the period of extended operation.

In LRA Appendix C, the applicant stated that the UFSAR supplement, contained in LRA Appendix A, includes a summary description of the programs and activities, as required by this AAI. The staff confirmed that the applicant included the applicable UFSAR supplements, for each of the TLAAs, in accordance with 10 CFR 54.21(c)(1)(d). These UFSAR supplements include the following for TLAAs related to reactor vessel and reactor vessel internal components:

- UFSAR supplement A.4.2 and the following subsections for each of the five TLAAs on neutron irradiation embrittlement of RV beltline components:
  - A.4.2.2 on the upper-shelf energy assessment
  - A.4.2.3 on the ART assessment
  - A.4.2.4 on the P-T limits assessment
  - A.4.2.5 on the RV axial weld inspection probability of failure analysis
  - A.4.2.6 on the RV circumferential weld inspection
- UFSAR supplement A.4.3 and its subsections for each of the two TLAAs on metal fatigue analyses for including the following:
  - A.4.3.1 on the ASME Code Section III, Class 1 Fatigue Analyses
  - A.4.3.4 on the RV internal components
- UFSAR supplement A.4.3.3 on the applicant's EAF analyses for specific ASME Code Class 1 components in the RCPB, including selected RV components.
- UFSAR supplement A.4.6.3 on the applicant's loss of preload analyses for RPV core plate rim hold-down bolt.

Based on this review, the staff finds that the applicant resolved the generically applicable AAI No. 2 from the perspective of TLAAs because it has included the appropriate UFSAR supplement sections for the TLAAs associated with the reactor vessel and its internal components in LRA Appendix A.

Other Specific Fatigue TLAA-Related AAIs Associated with BWRVIP Reports. LRA Appendix C identifies that the following BWRVIP guidelines include additional AAIs related to TLAAs:

- BWRVIP-18
- BWRVIP-25
- BWRVIP-26-A
- BWRVIP-42-A
- BWRVIP-47-A
- BWRVIP-74-A

The staff evaluates the applicant's responses to the TLAA-related AAIs in the following paragraphs.

BWRVIP-18, AAI No. 4: The AAI states the following: "Applicants referencing the BWRVIP-18 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject core spray internals components."

The response to AAI No. 4 in LRA Appendix C states that the metal fatigue TLAA disposition is discussed in LRA Section 4.3.4. The staff confirmed that the applicant included its TLAA on metal fatigue in LRA Section 4.3.4. Based on this review, the staff finds that the applicant resolved AAI No. 4 on BWRVIP-18-A because it included the appropriate metal fatigue TLAA for the core spray (CS) in LRA Section 4.3.4. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.3.4.2.

BWRVIP-25, AAI No. 4. The AAI states the following: "Due to the susceptibility of the rim hold-down bolts to stress relaxation, applicants referencing the BWRVIP-25 report for license renewal should identify and evaluate the projected stress relaxation as a potential TLAA issue."

The response to AAI No. 4 in LRA Appendix C states that preload of the rim hold-down bolts is required to prevent lateral motion of the core plate for those plants that do not have core plate wedges installed. Stress relaxation of the RPV core plate rim hold-down bolts has been identified as a TLAA issue as evaluated in LRA Section 4.6.3. The staff confirmed that the applicant included its TLAA on loss of preload in LRA Section 4.6.3. Based on this review, the staff finds that the applicant resolved AAI No. 4 on BWRVIP-25 because it included the appropriate TLAA for the rim hold-down bolts in LRA Section 4.6.3. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.6.3.2.

BWRVIP-26-A, AAI No. 4. The AAI states the following: "Due to [irradiation-assisted stress corrosion cracking] IASCC susceptibility of the subject safety-related components, applicants referencing the BWRVIP-26 report for license renewal should identify and evaluate the projected accumulated neutron fluence as a potential TLAA issue."

The response to AAI No. 4 in LRA Appendix C states that accumulated neutron fluence for the top guide is not a TLAA for LGS Units 1 and 2 because the top guide has exceeded the threshold fluence levels for IASCC identified in BWRVIP-26-A. The applicant also stated that the aging effect is managed by inspections conducted as part of BWR Vessel Internals program per guidance in BWRVIP-183. The staff confirmed that, in LRA Table 3.1.2-3, the applicant identified that cracking is an applicable aging effect requiring management for the top guide and credits its BWR Vessel and Internals program for aging management. The staff finds that the applicant does not need to treat the fluence level for the top guide as a TLAA because the applicant postulates cracking as an applicable aging effect for the top guide components and credits its BWR Vessel and Internals program and its BWRVIP-183 inspections for aging management. The staff noted that this approach includes management of IASCC, which may be induced when the neutron fluence exceeds the threshold defined in BWRVIP-26-A. The staff's evaluation of the BWR Vessel Internals program is documented in SER Section 3.0.3.2.2. Based on this review, the staff finds that the applicant resolved AAI No. 4 of BWRVIP-26-A.

BWRVIP-42-A, AAI No. 4. The AAI states the following: "Applicants referencing the BWRVIP-42 report for license renewal should identify and evaluate any potential TLAA issues which may impact the structural integrity of the subject RPV internals components."

The response to the AAI in LRA Appendix C states that the metal fatigue TLAA disposition is discussed in LRA Section 4.3.4. The staff confirmed that the applicant included its TLAA on metal fatigue for reactor vessel internals (RVIs) in LRA Section 4.3.4. Based on this review, the staff finds that the applicant resolved AAI No. 4 on BWRVIP-42-A because it included the appropriate metal fatigue TLAA for the CS in LRA Section 4.3.4. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.3.4.2.

BWRVIP-47-A, AAI No. 4. The AAI states the following: "Due to fatigue of the subject safety-related components, applicants referencing the BWRVIP-47 report for LR should identify and evaluate the projected CUF as a potential TLAA issue."

The response to the AAI in LRA Appendix C states that the fatigue usage is considered a TLAA for RVIs, including the lower plenum, and is discussed in LRA Section 4.3.4. The staff confirmed that the applicant included its TLAA on metal fatigue in LRA Section 4.3.4. Based on this review, the staff finds that the applicant resolved AAI No. 4 on BWRVIP-47-A because it included the appropriate metal fatigue TLAA for the lower plenum in LRA Section 4.3.4. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.3.4.2.

BWRVIP-74-A, AAI No. 8. The AAI states the following:

> LR applicants should verify that the number of cycles assumed in the original fatigue design is conservative to assure that the estimated fatigue usage for 60 years of plant operation is not underestimated. The use of alternative actions for cases where the estimated fatigue is projected to exceed 1.0 will require case-by-case staff review and approval. Further, a LR applicant must address environmental fatigue for the components listed in the BWRVIP-74 report for the LR period.

The response to the AAI in LRA Appendix C states that the RVIs fatigue analyses are evaluated as TLAAs in LRA Section 4.3.4. The response further stated that transient cycle projections demonstrate that current transient cycle limits will not be exceeded during the period of extended operation. The response also stated that environmental fatigue for reactor vessel components is addressed in LRA Section 4.3.3 with results shown in LRA Table 4.3.3-1.

The staff confirmed that the applicant included the applicable metal fatigue TLAAs for the RV and RV internals components in LRA Sections 4.3.1 and 4.3.4, respectively. The staff also confirmed that transient cycle projections and EAF evaluations are included in LRA Sections 4.3.1 and 4.3.3, respectively. Based on this confirmation, the staff finds that the applicant's response to AAI No. 8 is acceptable and resolves the AAI item because the applicant has included the applicable EAF evaluations and metal fatigue TLAAs for these components in LRA Sections 4.3. The staff's evaluations of the applicant's disposition of the EAF evaluations and TLAAs for the RV and its internal components are documented in SER Sections 4.3.3.2, 4.3.1.2, and 4.3.4.2, respectively.

BWRVIP-74-A, AAI No. 9. The AAI states the following: "Appendix A to the BWRVIP-74 report indicates that a set of P-T [Pressure-Temperature] curves should be developed for the heat-up and cool-down operating conditions in the plant at a given EFPY in the LR periods."

The response to the AAI in LRA Appendix C states that P-T limit curves will be developed for the period of extended operations consistent with the requirements of Appendix G to 10 CFR, Part 50, and is described in LRA Section 4.2.4. The staff confirmed that the applicant included its TLAA on P-T limit curves in LRA Section 4.2.4. Based on this review, the staff finds that the applicant resolved AAI No. 9 on BWRVIP-74-A because it included the appropriate P-T Limit curve TLAA in LRA Section 4.2.4. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.2.4.2.

BWRVIP-74-A, AAI No. 10. The AAI states the following:

> To demonstrate that the beltline materials meet the Charpy USE criteria specified in Appendix B of the report, the applicant shall demonstrate that the percent reduction in Charpy USE for their beltline materials are less than those specified for the limiting BWR/3-6 plates and the non-Linde 80 submerged arc welds and that the percent reduction in Charpy USE for their surveillance weld and plate are less than or equal to the values projected using the methodology in RG 1.99, Revision 2.

The response to the AAI in LRA Appendix C states that Charpy USE values for the period of extended operation were determined using methods consistent with RG 1.99, Revision 2, and is described in LRA Section 4.2.2 with results displayed in LRA Tables 4.2.2-1 and 4.2.2-2. The staff confirmed that the applicant included its TLAA on Charpy USE in LRA Section 4.2.2. Based on this review, the staff finds that the applicant resolved AAI No. 10 on BWRVIP-74-A because it included the appropriate Charpy USE TLAA in LRA Section 4.2.2. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.2.2.2.

BWRVIP-74-A, AAI No. 11. The AAI states the following:

> To obtain relief from the in-service inspection of the circumferential welds during the LR period, the BWRVIP report indicates each licensee will have to demonstrate that (1) at the end of the renewal period, the circumferential welds will satisfy the limiting conditional failure frequency for circumferential welds in Appendix E for the staff's July 28, 1998, SER; and (2) that they have implemented operator training and established procedures that limit the frequency of cold overpressure events to the amount specified in the staff's FSER.

The response to the AAI in LRA Appendix C states that at the end of the renewal period the circumferential welds for each unit will satisfy the limiting conditional failure frequency in the staff's July 28, 1998 FSER, and that the discussion of the relief from ISI inspection of circumferential welds is in LRA Section 4.2.6. The staff confirmed that the applicant included its TLAA on circumferential weld inspections in LRA Section 4.2.6 and that the applicant demonstrated the 2 items discussed in the AAI have been satisfied. Based on this review, the staff finds that the applicant resolved AAI No. 11 on BWRVIP-74-A. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.2.6.2.

BWRVIP-74-A, AAI No. 12. The AAI states the following:

> As indicated in the staff's March 7, 2000, letter to Carl Terry, a LR applicant shall monitor axial beltline weld embrittlement. One acceptable method is to determine that the mean RT_{NDT} [reference temperature nil ductility transition] of the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of this FSER.

The response to the AAI in LRA Appendix C states that the mean RT_{NDT} of the limiting axial beltline weld for each unit at the end of the period of extended operation is less than the value specified in Table 1 of BWRVIP-74-A FSER and the axial weld inspection TLAA is discussed in LRA Section 4.2.5. The staff confirmed that the applicant included its TLAA on axial welds in LRA Section 4.2.5 and that the limiting axial beltline weld at the end of the period of extended operation is less than the values specified in Table 1 of the BWRVIP-74-A FSER. Based on this review, the staff finds that the applicant resolved AAI No. 12. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.2.5.2.

BWRVIP-74-A, AAI No. 13. The AAI states the following:

> The Charpy USE, P-T limit circumferential weld and axial weld RPV integrity evaluations are all dependent upon the neutron fluence. The applicant may perform neutron fluence calculations using staff approved methodology or may submit the methodology for staff review. If the applicant performs the neutron flluence calculation using a methodology previously approved by the staff, the applicant should identify the NRC letter that approved the methodology.

The response to the AAI in LRA Appendix C states that an NRC approved methodology was used to determine fluence during the period of extended operation and that the methodology used was approved within the SER for BWRVIP-114, 115, 117, and 121, and that the discussion of the fluence methodology is in LRA Section 4.2.1. The staff confirmed that the applicant included its TLAA on fluence in LRA Section 4.2.6. Based on this review, the staff finds that the applicant resolved AAI No. 13 on BWRVIP-74-A because the applicant referenced a previously approved methodology and referenced the NRC approval for the referenced methodology. The staff's evaluation of the applicant's disposition for this TLAA is documented in SER Section 4.2.1.2.

<u>*TLAA-Related AAI Response Conclusion*</u>. Based on this review, the staff concludes that the applicant either provided a response the staff found acceptable or resolved all of the staff's requests raised in applicable TLAA-related AAIs of the BWRVIP reports referenced in the SER. The applicant's responses to the TLAA-related AAIs are resolved.

4.1.2.2 Identification of Exemptions in the LRA

As required by 10 CFR 54.21(c)(2), the applicant must identify all exemptions granted under 10 CFR 50.12 that are based on a TLAA and evaluate them and justify their use during the period of extended operation. The staff reviewed the LGS Units 1 and 2 CLBs to see if they included any exemptions granted in 10 CFR 50.12 and based on a TLAA. The staff reviewed the current operating license and Technical Specifications for the facility and the applicant's UFSAR. The staff's review also included a search of the NRC's official recordkeeping system (main and legacy libraries in the Agencywide Documents Access and Management System (ADAMS)) using the keyword "exemption."

The staff noted that the P-T limits for the reactor vessel and RCPB are based on compliance with the P-T limit generation requirements in 10 CFR Part 50, Appendix G. For LGS Unit 1, the applicant requested an exemption from 10 CFR Part 50, Appendix G, to permit the use of ASME Code Cases N-588 and N-640. The staff noted that the 32 Effective Full Power Year (EFPY) P-T limits were granted for LGS Unit 1 for Cycle 9 in License Amendment No. 145 dated September 15, 2000. The 32 EFPY P-T limits were granted for Unit 2, for Cycle 7 in License Amendment No. 111 dated March 21, 2001.

In LRA Section 4.2.1, the applicant projected 35 EFPY and 37 EFPY will be accumulated at the end of the 40 years operation for LGS Units 1 and 2, respectively. Thus, the staff needed to assess whether the exemptions will be needed during the period of extended operation under two scenarios: 1) if the actual EFPY at the end of the 40 years operation will be greater than 32 EFPY; and 2) if the actual EFPY at the end of the 40 years operation will be less than 32 EFPY.

For the first scenario that the actual EFPY will be greater than 32 EFPY, the applicant is required to obtain a new P-T limit based on the requirements in 10 CFR Part 50, Appendix G. Thus, the current exemptions will be replaced and no longer in effect during the period of extended operation. For the second scenario that the actual EFPY will be less than 32 EFPY, however, the applicant did not provide an evaluation to justify the continuation of the exemptions for the period of extended operation, as required by 10CFR 54.21(c)(2). By letter dated July 10, 2012, the staff issued RAI 4.1-3 requesting the applicant provide an evaluation that justified the continuation of those exemptions associated with Code Cases N-640 and N-588 in the event that the current approved P-T limits would be in effect during the period of extended operation.

In its response dated July 11, 2012, the applicant stated that the staff approved the exemptions in letters dated September 7, 2000 for LGS Unit 1 and March 21, 2001 for LGS Unit 2. The applicant also updated LRA Table 4.1-3, which corrected the LGS Unit 1 exemption approval date. The staff noted that these two approved exemptions placed restriction of their use for one operating cycle on each unit. Based upon subsequent fluence data submitted by the applicant in letter dated June 26, 2002, the staff granted the use of the Code Cases, without restriction, for both units on January 2, 2003 for LGS Unit 1 in License Amendment No. 163 as well as for LGS Unit 2 in License Amendment No. 125.

The applicant justified that continuation of the exemption into the period of extended operation because the use of Code Cases as a basis for the 32 EFPY P-T limits was approved by the staff. The staff reviewed the safety evaluation for the exemption in the license amendment dated January 2, 2003, and confirmed that use of the exemptions were extended for both units to 32 EFPY without any limitation with respect to number of years of plant operation. Thus, the staff finds it acceptable that the current exemptions continue to be in effect during the period of extended operation if the actual EFPY at the end of the 40 years operation will be less than 32 EFPY. The applicant also revised LRA Sections 4.1.5 and A.4.1 to reflect that the exemptions are identified and justified for continuation during the period of extended operation. Based on its review, the staff finds the applicant's response to RAI 4.1-3 acceptable because the applicant provided an evaluation to justify the continuation of the exemptions for the period of extended operation, as required by 10CFR 54.21(c)(2).

The staff also noted that Section 2.D, in both LGS Unit 1 Operating License NPF-39 and LGS Unit 2 Operating License NPF-85, identified that the applicant was granted a number of exemptions from the requirements in 10 CFR Part 50, Appendix J. The staff noted that the exemptions involve the method of performing leak rate testing of the containment and MSIVs. The staff also noted that those tests are discussed in UFSAR Section 6.2.6 and the exemptions on the method of testing do not involve time-limited assumptions defined by the current operating term. Thus, these exemptions on the leak-rate testing do not meet Criterion 3 of 10 CFR 54.3(a) for the definition of a TLAA and the exemption identification criterion in 10 CFR 54.21(c)(2).

Based on its review and the information provided by the applicant, the staff concludes, in accordance with 10 CFR 54.21(c)(2), that the applicant has provided a list of plant-specific exemptions granted and in effect that are based on TLAAs and the applicant has provided an evaluation that justify the continuation of these exemptions for the period of extended operation.

4.1.3 UFSAR Supplement

LRA Section A.4.1, as amended by letter dated July 11, 2012, provides the UFSAR supplement summarizing the identification of TLAA and exemptions. Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.1.2 which states that UFSAR supplement descriptions are provided for each identified TLAA. Additionally, the staff determines that the applicant provided an adequate summary description to address TLAA and exemptions identification, as required by 10 CFR 54.21(d).

4.1.4 Conclusion

Based on its review, the staff concludes that the applicant provided an accurate lists of TLAAs, as required by 10 CFR 54.21(c)(1). The staff concluded that the applicant has identified the appropriate exemptions granted under the requirements in 10 CFR 50.12 and that are based on a TLAA, as required by 10 CFR 54.21(c)(2).

4.2 Reactor Pressure Vessel Neutron Embrittlement

LRA Section 4.2 describes the neutron embrittlement analyses performed for LGS Units 1 and 2. The LRA states that the beltline region of the RV includes the reactor vessel plates, welds and forging materials that are predicted to receive a cumulative neutron exposure that exceeds 1.0×10^{17} neutrons/cm^2 during the licensed life of the plant.

The LRA states that the TLAAs related to neutron embrittlement are the following:

- neutron fluence projections (LRA Section 4.2.1)
- upper-shelf energy (LRA Section 4.2.2)
- ART (LRA Section 4.2.3)
- pressure – temperature limits (LRA Section 4.2.4)
- axial weld inspection (LRA Section 4.2.5)
- circumferential weld inspection (LRA Section 4.2.6)
- RPV reflood thermal shock (LRA Section 4.2.7)
- RPV core plate rim hold-down bolt loss of preload (LRA Section 4.6.3)
- jet pump auxiliary spring wedge assembly (LRA Section 4.6.5)
- jet pump restrainer bracket pad repair clamps (LRA Section 4.6.6)
- jet pump slip joint repair clamps (LRA Section 4.6.9)

4.2.1 Neutron Fluence

4.2.1.1 Summary of Technical Information in the Application

LRA Section 4.2.1 summarizes the evaluation of neutron fluence for the period of extended operation. To evaluate the effects of neutron irradiation embrittlement on the safety-related fracture toughness analyses for the RPV beltline components, the applicant indicated that analyses were performed to determine the neutron fluence projections for the RPV beltline components through 57 EFPY of operations, which is the projected EFPY associated with 60 years of licensed operations. The applicant stated that the projections account for a 5 percent increase in power approved and implemented for LGS Unit 1 starting in cycle 7 and for LGS Unit 2 in cycle 4, and an additional 1.65 percent increase in power approved and implemented for LGS Unit 1 during midcycle 14 and implemented for LGS Unit 2 at the beginning of operating cycle 12.

The applicant stated that the 57 EFPY neutron fluences (E > 1.0 MeV) for the RPV beltline shell, weld, and nozzle components at LGS were calculated using the Radiation Analysis Modeling Application (RAMA) fluence methodology (RAMA code fluence methodology) that was developed for the Electric Power Research Institute (EPRI) and the BWRVIP. The applicant stated that use of this methodology was performed consistent with the recommendations and guidelines presented in RG 1.190. The applicant stated that the RAMA code fluence methodology was also used to determine the 57 EFPY neutron fluence values for the RVI components at Units 1 and 2.

The applicant stated that each of the LGS fluence projection models are based upon quadrant azimuthal symmetry, which means one quarter of the reactor core was modeled in detail to provide an accurate representation of the core configuration. The models also include accurate geometric representations of the RPV, including the N16 water level instrumentation (WLI) nozzles and the N17 low-pressure coolant injection (LPCI) nozzles and their associated nozzle-to-vessel weld, which are included in the reactor vessel beltline. The applicant references EPRI Report No. 1007283, "BWR Vessel and Internals Project, RAMA Fluence Methodology Software (BWRVIP-126)," dated 2003, as the applicable RAMA code fluence methodology for the 57 EFPY neutron fluence projections used in the neutron irradiation embrittlement assessment TLAAs in the LRA. The applicant stated that this methodology was reviewed and approved by the staff.

The applicant stated that the RVP fluence values were determined at the interface of the RPV base metal and cladding (0T) for the RPV beltline materials, which include the RPV lower shell plates, RPV lower-intermediate shell plates, RPV axial welds (i.e., RPV weld designations BA, BB, BC, BD, BE, BF, BG, BH, and BJ), RPV circumferential weld AB, the N16 WLI nozzles, and the N17 LPCI nozzles and their associated nozzle-to-vessel welds. The applicant stated that the fluence projections for these nozzles are based upon the highest fluence value at the edge of each cutout location within the shell plate and, therefore, are considered applicable for the nozzle welds. The applicant identified that the N16 WLI instrumentation nozzles and welds are fabricated from nickel-alloy materials. As such, the applicant states that these nozzles and welds are not required to be evaluated for loss of fracture toughness by the requirements in 10 CFR Part 50, Appendix G, because the components are not fabricated from ferritic materials.

The applicant stated that the 1/4T fluence values for the RPV beltline components were then determined from the 0T values using two different methods permitted by RG 1.99, Revision 2. The applicant stated that the first of these 1/4T fluence value methods used a plant-specific calculation of displacements per atom (dpa) in iron, substituting the ratio of dpa at the 1/4T depth to the dpa at 0T in place of the exponential attenuation factor in Equation 3.

The applicant stated that the second of these methods used the generic exponential attenuation formulation provided in Equation 3. The applicant stated that since the 1/4T values obtained using the plant-specific dpa method were higher than those resulting from the generic attenuation method, the plant-specific 1/4T fluence values were used in evaluating the neutron embrittlement TLAAs.

LRA Table 4.2.1-1 provides the 57 EFPY fluence projections for Unit 1, reactor vessel beltline shells (plates), girth (circumferential) welds and axial (vertical) welds. LRA Table 4.2.1-2 provides the 57 EFPY fluence projections for LGS Unit 1 beltline nozzle forgings.

Table 4.2.1-3 shows the 57 EFPY fluence projections for Unit 2, reactor vessel beltline shells (plates), girth (circumferential) welds and axial (vertical) welds. Table 4.2.1-4 shows the 57 EFPY fluence projections for LGS Unit 2 beltline nozzle forgings.

The applicant stated that the bounding fluence value determined for each RPV shell ring at Units 1 and 2 is to be used in the evaluation of all three plates within each shell. For Shell 3 of both LGS Units 1 and 2, the highest 57 EFPY neutron fluence for that shell was less than 1.0×10^{17} neutrons/cm^2 and thus these materials were not evaluated for USE or ART.

4.2.1.2 Staff Evaluation

The staff reviewed the applicant's information against the criteria in RG 1.190, Revision 0, "Calculational and Dosimetry Methods for Determining Pressure Vessel Neutron Fluence," issued March 2001. The staff noted that the LRA cited BWRVIP-126 as the applicable BWRVIP fluence methodology for conforming to the recommendations of RG 1.190, Revision 0. The staff noted that the BWRVIP report cited in the LRA only referred to the software programming (i.e., RAMA) used to calculate the LGS 57 EFPY. However, in reviewing the applicant's most recent P-T limits for Units 1 and 2 (approved by license amendment No. 163 in January 2003), the staff noted that the GE Company Report No. NEDC-32983P-A methodology was used to derive the 32 EFPY neutron fluence values for the LGS P-T limit curves. Thus, the staff noted that the LRA was not clear about which methodology was adopted by the applicant in its CLB (i.e., BWRVIP or GE report) to conform to RG 1.190, nor did the LRA provide the appropriate basis to justify why the previously-approved methodology in GE Report No. NEDC-32983P-A was not used for derivation of the 57 EFPY neutron fluences values for the LRA.

By letter dated May 18, 2012, the staff issued RAI 4.2.1-1, requesting the applicant to provide its basis for referencing the use of RAMA Code methodology to calculate neutron fluence for TLAAs in the LRA, when such methodology has not been previously identified as part of the applicant's CLB. As part of its response, the staff also asked the applicant to clearly identify, by document reference number, title, and date, all neutron fluence methodologies that are in the LGS CLB to conform to the regulatory position in RG 1.190 and to clarify whether the neutron fluence methodologies adopted in the CLB has been endorsed for use by the NRC. The staff also asked the applicant to clarify how any and all relevant limitations and conditions placed on implementation of the fluence calculation methodologies adopted in the LGS CLB have been addressed.

The applicant responded to RAI 4.2.1-1 by letter dated May 31, 2012. In its response, the applicant stated that the use of the RAMA code methodology for calculating neutron fluence values (RAMA code fluence methodogy) was benchmarked against the plant-specific dosimetry measurement results and reported fluence values from several commercial operating reactors. The applicant stated that the RAMA code fluence methodology was reviewed and approved in a NRC safety evaluation for the following reports:

- BWRVIP-114, "BWRVIP RAMA Fluence Methodology Manual"
- BWRVIP-115, "RAMA Fluence Methodology Benchmark Manual (BWRVIP-115),"
- BWRVIP-117, "RAMA Fluence Methodology – Susquehanna Unit 2, Surveillance Capsule Fluence Evaluation for Cycles 1-5,"
- BWRVIP-121, "RAMA Fluence Methodology Procedures Manual"
- Hope Creek Evaluation TWE-PSE-001-R-001, "Hope Creek Flux Wire Dosimeter Activation Evaluation for Cycle 1"

The applicant stated that in the safety evaluation for the above documents, dated May 13, 2005, the staff concluded that the use of the BWRVIP RAMA code fluence methodology provides an acceptable "best estimate" methodology for predicting the fast neutron fluencies (for neutrons with kinetic energies E > 1.0 Mev) of BWR RPVs.

According to the applicant, the LGS and Susquehanna reactor units have similar designs with respect to the design of the reactor vessels fuel assemblies, core shrouds, and jet pump assemblies. For this reason, the applicant stated that the application of the RAMA code fluence methodology is appropriate for use at LGS because: (a) the LGS reactor units are BWR-IV reactors that are similar in design to the reactors for Susquehanna nuclear plant units; and (b) the NRC conditions for use of RAMA methodology have been met. Based on this determination, the applicant concluded that the RAMA code neutron fluence methodology can be applied for the neutron fluence determinations of the LGS RPVs without a bias, as endorsed in the NRC SE on use of the RAMA code methodology.

The applicant also stated that BWRVIP integrated surveillance program was approved by License Amendment No. 167 for LGS Unit 1 and Amendment No. 130 for LGS Unit 2, dated November 4, 2003.

The applicant indicated that these license amendments define the CLB for computing neutron fluence at LGS and that UFSAR Sections 4.1.4.5 and 4.3.2.8 were revised accordingly to state: "LGS RPV fluence has been evaluated using a method in accordance with the recommendations of RG 1.190. Future evaluations of RPV fluence will be completed using a method in accordance with the recommendations of RG 1.190."

The applicant stated that the RAMA code methodology has since been evaluated and adopted for use at LGS through implementation of the applicant's 10 CFR 50.59 design change process.

The applicant stated that the 57 EFPY neutron fluence values calculated for 60 years of operation using RAMA were used in the following sections of the LRA: Section 4.2.2, "Upper-Shelf Energy;" Section 4.2.3, "Adjusted Reference Temperature;" Section 4.2.5, "Axial Weld Inspection;" Section 4.2.6, "Circumferential Enclosure Weld Inspection;" and Section 4.2.7, "Reactor Pressure Vessel Reflood Thermal Shock." The applicant stated that it is not currently adopting the RAMA code fluence methodology for LRA 4.2.4, "Pressure Temperature Limits," because the P-T limit curves have not been revised as part of the LRA. The staff notes that the P-T limits are included in the LGS Units 1 and 2 technical specification and the revision of the P-T limits for the period of extended operation will require a license amendment pursuant to 10 CFR 50.90. Therefore, the use of RAMA code fluence methodology for use in development of P-T limits will be subject to NRC review and approval for the period of extended operation.

The applicant's response to RAI 4.2.1-1 indicates that NRC-approved Report BWRVIP-117, "RAMA Fluence Methodology – Susquehanna Unit 2, Surveillance Capsule Fluence Evaluation for Cycles 1-5," was the BWRVIP RAMA code fluence methodology report that was most appropriate for application to the LGS CLB caused by the similarity of the LGS and Susquehanna reactor designs. Therefore, the staff compared the UFSAR reactor design parameters reported in the UFSAR for the Susquehanna units to those reported in the UFSAR for the LGS units to determine whether the Susquehanna reactor design provides a valid bounding basis for applying Report BWRVIP-117 to the LGS CLB. The staff confirmed that the LGS and Susquehanna reactors are all BWR Model IV reactors that have similar reactor and reactor vessel internal designs. Based on its verification of the design date, the staff determined that the assumptions in Report BWRVIP-117 would be applicable to the LGS reactor design.

From a review of the safety evaluation for the RAMA code fluence methodology, dated May 13, 2005, the staff determined that the generic SE endorsing use of the RAMA code fluence methodology for calculation of neutron fluence values in the U.S. BWR nuclear industry is applicable to LGS Units 1 and 2.

Therefore, with the exception of the relationship of the RAMA code fluence methodology to the P-T limits TLAA, the staff concludes that the applicant has adequately demonstrated that the RAMA code fluence methodology is appropriate for application to those remaining neutron fluence based TLAAs in the LRA.

Based on this review, the staff finds that the applicant can apply the 57 EFPY neutron fluence values reported in LRA Section 4.2.1 to the assessment of the USE analysis (LRA Section 4.2.2), the ART analysis (LRA Section 4.2.3), the circumferential weld and axial weld probability of failure analyses (LRA Sections 4.2.5 and 4.2.6), and the GE RPV reflood thermal shock analysis (LRA Section 4.2.7), and for the fluence-based RPV core plate rim hold-down bolt loss of preload analysis (LRA Section 4.6.3).

For application to the TLAAs related to the generation of the P-T limits for the period of extended operation (i.e., the TLAAs in LRA Section 4.2.3 and 4.2.4), pursuant to the requirements in 10 CFR 50.90, the applicant will be required to submit P-T limits for the period of extended operation for staff review and have the updated P-T limits approved before the expiration of the 32 EFPY P-T limit curves in the technical specifications (i.e., the current P-T limit curves approved for the CLB).

RAI 4.2.1-1 is resolved.

4.2.1.3 UFSAR Supplement

The applicant provided a UFSAR supplement summary description of its TLAA evaluation of neutron fluence in LRA Section A.4.2.1. Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of the neutron fluence methodology that was used to establishing the 57 EFPY neutron fluencies reported in LRA Section 4.2, as required by 10 CFR 54.21(d).

4.2.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(ii), that the 57 EFPY neutron fluence values reported for the RPV beltline materials, and for the RPV core plate rim hold-down bolts, have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.2 Upper-Shelf Energy

4.2.2.1 Summary of Technical Information in the Application

LRA Section 4.2.2 summarizes the applicant's evaluation of Charpy USE values for the period of extended operation. The applicant evaluated compliance with the requirements of 10 CFR Part 50, Appendix G, using the projected 57 EFPY fluences described in LRA Section 4.2.1, as attenuated to the 1/4T location in the wall thickness.

Charpy USE values for most of the materials of the LGS Units 1 and 2 RVs were determined consistent with the guidance in RG 1.99, Revision 2, without the use of surveillance data (Position 1.2 of the RG). The exception is LGS Unit 1 weld heat 5P6756 from the BWRVIP Integrated Surveillance Program, which is the only material applicable for LGS that has credible surveillance data. Position 2.2 was used to compute the USE value for weld heat 5P6756. The projected USE values for the RV beltline materials were determined to remain in compliance with 10 CFR Part 50, Appendix G, requirements, either by demonstrating USE values of at least 50 ft-lb or through an equivalent margins analysis (EMA).

The applicant dispositions this TLAA in accordance with 10 CFR 54.21 (c)(1)(ii), that the analyses have been projected to the end of the period of extended operation.

4.2.2.2 Staff Evaluation

The staff reviewed LRA Section 4.2.2, in accordance with the review procedures of SRP-LR Section 4.2.3.1.1.2, to verify that the Charpy USE analyses have been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii). The staff determined the chemistry and initial USE values provided in LRA Section 4.2.2 are consistent with those provided in the recent license amendment request for a power uprate (approved in Amendment Nos. 201 and 163, for Units 1 and 2, respectively, on April 8, 2011). Thus, the values are consistent with the CLB for LGS Units 1 and 2. Acceptance criteria for this review are in accordance with SRP-LR Section 4.2.2.1.1.2.

Appendix G to 10 CFR Part 50 contains the screening criteria that establish limits on the USE values for RV materials after neutron irradiation exposure. The regulation requires the value of USE be greater than 50 ft-lbs in the irradiated condition throughout the licensed life of the plant. USE values of less than 50 ft-lbs may be acceptable to the staff if it can be demonstrated that these lower values will provide margins of safety against brittle fracture equivalent to those required by ASME Code Section XI, Appendix G.

Consistent with RG 1.99, Revision 2, the predicted decrease in USE values caused by neutron embrittlement during plant operation is dependent upon the type of material (weld or base plate), the amount of copper (Cu) in the material, and the predicted neutron fluence for the material. The RG outlines two ways to project the USE values for ferritic steels: Position 1.2 uses curves of percent decrease in USE as a function of Cu content and neutron fluence (in the absence of "credible reactor surveillance data) and Position 2.2 determines percent decrease in USE based on the reactor surveillance data. The applicant stated that it used Position 1.2 to determine the Charpy USE values at the end of the period of extended operation for all of the RV beltline materials except for LGS Unit 1 weld heat number 5P6756, which uses Position 2.2 because it was the only material with credible surveillance data available.
As part of its review to confirm acceptability of the applicant's analysis, the staff performed a USE evaluation for each of the beltline materials as described in Position 1.2. In all cases, the applicant's projected USE values from Tables 4.2.2-1 and 4.2.2-2 were equal to or less than that calculated by the staff, which confirms the conservative nature of the applicant's evaluation. In the case of LGS Unit 1 weld heat number 5P6756, the staff's prediction from Position 1.2 is essentially the same as the applicant's prediction based on Position 2.2.

Several materials for each unit had projected USE values below 50 ft-lbs at 57 EFPY. In each case, the applicant demonstrated equivalence to 10 CFR 50 Appendix G requirements through an EMA using the methodology provided in BWROG-94037, "BWR Owners' Group Topical Report on Upper-Shelf Energy Equivalent Margin Analysis – Approved Version," March 21, 1994, and NEDO-32205-A, Revision 1, "10 CFR Part 50, Appendix G, Equivalent Margin Analysis for Low Upper-Shelf Energy in BWR/2 through BWR/6 Vessels," issued February 1994. For these materials with projected USE values less than 50 ft-lbs, the staff confirmed that the projected percent decrease in the USE value using Position 1.2 of RG 1.99, Revision 2, is less than the corresponding approved value from the EMA.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(ii) that the USE analyses for the RV beltline materials have been projected to the end of the period of extended operation. Additionally, the analyses meet the acceptance criteria in SRP-LR Section 4.2.2.1.1.2 because either the projected USE values at the end of the period of extended operation are above 50 ft-lbs or the percent decrease in USE value is bounded by an approved EMA.

4.2.2.3 UFSAR Supplement

LRA Section A.4.2.2 provides the UFSAR supplement summarizing the TLAA evaluation of USE. The staff reviewed LRA Section A.4.2.2, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of USE, as required by 10 CFR 54.21(d).

4.2.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the USE analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.3 Adjusted Reference Temperature

4.2.3.1 Summary of Technical Information in the Application

LRA Section 4.2.3 summarizes the ART evaluation of the LGS RV beltline materials for the period of extended operation. The applicant states that the fluence values used to calculate the ART values are from plant-specific displacements-per-atom attenuation calculations described in LRA Section 4.2.1 and consistent with RG 1.99, Revision 2, instead of the generic attenuation model outlined in RG 1.99, Revision 2, because the plant-specific values were slightly higher (more conservative). The applicant states that the ART values at the 1/4T location for the limiting beltline materials remain below 200 °F, consistent with the guidance in [Regulatory Position 3] of RG 1.99, Revision 2 [which apply for a new plant].

A summary of the limiting ferritic materials at each unit are as follows:

<u>Unit 1</u>	<u>Plate</u>	<u>N16 Nozzles</u>	<u>LCPI Nozzles</u>	<u>Weld</u>
ART	+74 °F	+48 °F	+61 °F	+16 °F
Heat No.	C7677-1	17-2	Q2Q25W	5P6756
<u>Unit 2</u>	<u>Plate</u>	<u>N16 Nozzles</u>	<u>LCPI Nozzles</u>	<u>Weld</u>
ART	+102 °F	+38 °F	+61 °F	+69 °F
Heat No.	B3416-1	C9526-1	Q2Q25W	5P6756

The LRA states that the information provided for the N16 nozzles is based upon that for the ferritic steel plate adjacent to the nozzle because the N16 nozzles are nickel alloy and do not require evaluation in accordance with Appendix G to 10 CFR Part 50.

The applicant dispositions this TLAA for the ART values of the RV beltline materials in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected for the period of extended operation.

4.2.3.2 Staff Evaluation

The staff reviewed LRA Section 4.2.3 to verify that the ART analyses have been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii), and consistent with RG 1.99, Revision 2.

Consistent with the guidance of RG 1.99, Revision 2, the ART value for each beltline material is evaluated from:

$ART = RT_{NDT(u)} + \Delta RT_{NDT} + M$

where $RT_{NDT(u)}$ is the unirradiated RT_{NDT} as defined in the ASME Code, Paragraph NB-2331, ΔRT_{NDT} is the mean value of the shift in RT_{NDT} caused by neutron irradiation, and M is the margin term to account for uncertainties in the calculation. The methodology used for determining ΔRT_{NDT} and the margin term M are described in RG 1.99, Revision 2.

In LRA Table 4.2.3-1 and 4.2.3-2, the applicant presented the ART values after 57 EFPY for LGS Units 1 and 2. Also presented in these tables are the input parameters necessary for calculating the ART values. The staff confirmed that the input parameters for the ART calculations are the same as those used in the recent power uprate amendment (approved April 8, 2011), and thus, are consistent with the CLB for LGS Units 1 and 2.

As part of its review to confirm acceptability of the applicant's analysis, the staff performed independent ART evaluations for each of the beltline materials in Table 4.2.3-1 and 4.2.3-2. In all cases, the applicant's projected ART values from Table 4.2.3-1 and 4.2.3-2 were equal to or greater than that calculated by the staff, which confirms the identity of the limiting materials.

Based on the above discussion, the staff concludes that the ART evaluations for RV beltline materials are consistent with the guidance of RG 1.99, Revision 2. The applicant's TLAA is acceptable because it meets the requirements of 10 CFR 54.21(c)(1)(ii) and will ensure that the LGS Units 1 and 2 RV materials will have adequate ART values and fracture toughness through the period of extended operation.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(ii), that the ART evaluations for the RV beltline materials have been projected to the end of the period of extended operation.

4.2.3.3 UFSAR Supplement

LRA Section A.4.2.3 provides the UFSAR supplement summarizing the TLAA evaluation of ART. The staff reviewed LRA Section A.4.2.3, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of ART, as required by 10 CFR 54.21(d).

4.2.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the ART analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.4 Pressure – Temperature Limits

4.2.4.1 Summary of Technical Information in the Application

LRA Section 4.2.4 summarizes the evaluation of the RV P-T limits, including heatup and cooldown operations for the period of extended operation. The current P-T limits, located in the technical specifications, were approved up to 32 EFPY. Before exceeding 32 EFPY, 10 CFR 50, Appendix G, requires new P-T limits to be developed for higher fluence values and approved by the NRC.

In addition, the applicant states that the Reactor Vessel Surveillance program provides data to update the P-T limits. Based on the available data, LGS Unit 1 is projected to exceed 32 EFPY during operating cycle 19, which begins in 2020. LGS Unit 2 is projected to exceed 32 EFPY during operating cycle 18, which begins in 2023.

The LRA indicates that SRP-LR Section 4.2.2.1.3 states that the P-T limits for the period of extended operation do not have to be submitted as part of the LRA, since the P-T limits are required to be updated through the 10 CFR 50.90 licensing process when necessary for P-T limits that are located in the Technical Specifications. The applicant stated that it plans to submit updates to the P-T limits for LGS Units 1 and 2 to the staff at the appropriate time and by the appropriate method to comply with 10 CFR 50, Appendix G.

The applicant dispositions the P-T limits TLAA for LGS Units 1 and 2 in accordance with 10 CFR 54(c)(1)(iii), that the effects of aging will be adequately managed for the period of extended operation.

4.2.4.2 Staff Evaluation

The staff reviewed LRA Section 4.2.4 to verify that the effects of aging on the P-T limits will be adequately managed by the applicant for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii). This review was consistent with SRP-LR Section 4.2.3.1.3.3 and the acceptance criteria of SRP-LR Section 4.2.2.1.3.3.

The staff notes that the current P-T limits, valid for operation up to 32 EFPY, were approved by the staff on January 2, 2003, in License Amendment 163 for LGS Unit 1 and License Amendment 125 for LGS Unit 2. The staff agrees that the updated P-T limit curves for the period of extended operation do not have to be submitted as part of the applicant's LRA. Before the expiration of each unit's current P-T limit curves, the applicant is required to submit revised P-T limits in accordance with 10 CFR Part 50, Appendix G, which considers the increase of the limiting ART value and plant-specific embrittlement information from any relevant surveillance data provided by the BWRVIP ISP. Hence, the staff finds that the applicant's plan to manage the P-T limits in accordance with 10 CFR 54.21(c)(1)(iii) is acceptable because revised P-T limit curves that meet the requirements of 10 CFR Part 50, Appendix G will be implemented by the appropriate method.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the P-T limits will be adequately managed for the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP-LR Section 4.2.2.1.3.3 because the plant-specific embrittlement parameters will be used to calculate the limits.

4.2.4.3 UFSAR Supplement

LRA Section A.4.2.4 provides the UFSAR supplement summarizing the TLAA evaluation of P-T limits. The staff reviewed LRA Section A.4.2.4, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of the P-T Limits, as required by 10 CFR 54.21(d).

4.2.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the P-T limits will be adequately managed during the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.5 Axial Weld Inspection

4.2.5.1 Summary of Technical Information in the Application

LRA Section 4.2.5 summarizes the TLAA evaluation of the RV axial weld inspection for the period of extended operation. The LRA states that BWRVIP-05, "BWR Reactor Pressure Vessel Shell Weld Inspection Recommendations," recommends that 100 percent of the axial

welds and only those sections of the circumferential welds that intersect with the axial welds should be inspected every 10 years. The LRA states that the recommendation for limited inspection of circumferential RV welds is based on generic probabilistic fracture mechanics analyses that predict the 40-year end-of-life axial weld probability of failure (PoF) is orders of magnitude greater than the 40-year end-of-life circumferential weld PoF. The LRA further states that the staff used this significant difference in the PoF for the axial and circumferential welds to justify relief from inspection of the circumferential welds as described in Generic Letter (GL) 98-05. The applicant has provided input data for comparison to the original bounding analysis found in the final NRC safety evaluation report (FSER) for BWRVIP-05, dated July 28, 1998. The comparison indicates that the limiting RV axial welds at LGS Units 1 and 2 at 57 EFPY are less likely to fail than the axial weld from the generic RV built by Chicago Bridge and Iron (CB&I) at 64 EFPY described in the FSER for BWRVIP-05, because the limiting mean RT_{NDT} values for LGS Units 1 and 2 (-4 °F and +9 °F, respectively) are less than that for the generic CB&I plant (+117.1 °F).
The applicant dispositioned the TLAA for the justification of the RV axial weld inspections in accordance with 10 CFR 54.21(c)(1)(ii), that the analyses have been projected for the period of extended operation.

4.2.5.2 Staff Evaluation

The staff reviewed LRA Section 4.2.5 to verify that the RV axial welds PoF has been projected to the end of the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(ii). This review was consistent with SRP-LR Section 4.2.3.1.5 and the acceptance criteria of SRP-LR Section 4.2.2.1.5.

The staff has confirmed that all of the input parameters (Cu and nickel (Ni) content, unirradiated RT_{NDT}, neutron fluence) used for the PoF calculation listed in LRA Table 4.2.5-1 are consistent with those used in the recent power uprate amendment (approved April 8, 2011), and thus, are consistent with the CLB for LGS Units 1 and 2. The bounding case is represented by a mean ART (ART without the margin term) of +117 °F for a limiting axial weld in a vessel manufactured by CB&I. The LGS-specific mean ART value for the Unit 1, limiting axial weld is -4 °F and is +9 °F for the limiting Unit 2, axial weld (both vessels were built by CB&I). Because the mean ART values for Units 1 and 2 are less than the comparable value for a CB&I-built vessel in the FSER for BWRVIP-05, the probability of failure for either of the two LGS RVs is less than the failure probability that was found acceptable in the FSER. Hence, the plant-specific analyses for LGS Units 1 and 2 are bounded by the FSER analysis and, therefore, are acceptable.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(ii), that the TLAA associated with the RV axial weld inspection has been projected to the end of the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.2.2.1.5.

4.2.5.3 UFSAR Supplement

LRA Section A.4.2.5 provides the UFSAR supplement summarizing the TLAA evaluation of the RV axial weld inspection. The staff reviewed LRA Section A.4.2.5, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of the RV axial welds inspection, as required by 10 CFR 54.21(d).

4.2.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses associated with the axial weld inspection have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.6 Circumferential Weld Inspection

4.2.6.1 Summary of Technical Information in the Application

LRA Section 4.2.6 summarizes the evaluation of the RPV circumferential weld inspection for the period of extended operation. LGS was granted RPV circumferential weld inspection relief from the ASME Code requirements for the original license period on September 13, 1999, in LGS ISI Program Relief Request RR-1. The relief was based on the evaluation of circumferential welds at LGS Units 1 and 2 and the limiting CB&I circumferential weld in the FSER for BWRVIP-05. The analysis has been projected to compare the mean 57 EFPY RT_{NDT} values for the limiting circumferential welds of LGS Units 1 and 2 with those for the limiting CB&I vessel in the FSER for BWRVIP-05. In this analysis, the actual RPV failure frequencies are not calculated, but, by comparison of the mean RT_{NDT} values, the applicant has demonstrated that the failure frequency for the LGS Units 1 and 2 RPV circumferential welds are bounded by the failure frequency calculated for the CB&I RPV circumferential welds in the FSER for BWRVIP-05. Specifically, the limiting mean RT_{NDT} values for the circumferential welds at LGS Units 1 and 2 (+10 °F and +9 °F, respectively) are less than that for the generic CB&I plant (+70.6 °F).

LRA Section 4.2.6 also states that operator training and procedures to limit the frequency of cold over-pressure events will continue as required by the staff's approval of the original relief request.

The applicant dispositioned the TLAA for the RPV circumferential weld inspection in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of neutron embrittlement on the intended functions will be adequately managed by reapplication for relief from the circumferential weld inspection under 10 CFR 50.55a(a)(3) before entering the period of extended operation.

4.2.6.2 Staff Evaluation

The staff reviewed LRA Section 4.2.6 to verify that the TLAA associated with RPV circumferential weld inspection will be managed for the period of extended operation, pursuant to 10 CFR 54.21(c)(1)(iii). The staff review was performed consistent with SRP-LR Section 4.2.2.1.4 and used Generic Letter 98-05.

The technical basis for the original relief request is found in the FSER for BWRVIP-05, which stated the following two requirements for the inspection relief:

(1) at the expiration of the license, the limiting conditional PoF for circumferential welds in the evaluation must be below the criterion specified in RG 1.154, "Format and Content of Plant-Specific Pressurized Thermal Shock Safety Analysis Reports for Pressurized Water Reactors," and core damage frequency (CDF) of any BWR plant, and

(2) the applicant must implement operator training and establish procedures that limit the frequency of cold overpressure events to the amount specified in the report

The staff has confirmed all of the input parameters (Cu and Ni content, unirradiated RT_{NDT}, neutron fluence) used for the PoF calculation listed in LRA Table 4.2.6-1 are consistent with those used in the recent power uprate amendment (approved April 8, 2011)), and thus, are consistent with the CLB for LGS Units 1 and 2.. The staff noted that the neutron fluence at 0T for the limiting LGS Units 1 and 2 circumferential welds in Table 4.2.6-1 did not agree with the comparable value reported in Tables 4.2.1-1 and 4.2.1-3 for fluence and Tables 4.2.3-1 and 4.2.3-3 for the temperature shift. In RAI 4.2.6-1, the staff requested that the applicant revise the LRA to reflect the accurate fluence projection. In its response dated January 24, 2012, the applicant submitted revised fluence values in Table 4.2.6-1 to be consistent with the comparable values in Tables 4.2.1-1 and 4.2.1-3 for fluence, and Tables 4.2.3-1 and 4.2.3-3 for the temperature shift. This revision to the LRA Table 4.2.6-1 resolves the staff concern expressed in RAI 4.2.6-1.

The first criterion from the FSER for BWRVIP-05 is addressed in LRA Table 4.2.6-1, where the applicant has summarized the effects of irradiation on the limiting circumferential welds at LGS Units 1 and 2 and compared these weld properties to the staff's limiting CB&I circumferential weld used in the July 28, 1998, FSER for BWRVIP-05. The staff notes that the LGS Units 1 and 2 circumferential welds have a lower copper content, as well as a lower neutron fluence at the clad/base metal interface than the limiting CB&I vessel circumferential weld. The unirradiated RT_{NDT} and Ni contents are higher for the LGS Units 1 and 2 circumferential welds. Overall, however, the effects of chemistry and neutron fluence contribute to lower the mean 57 EFPY ART for the LGS Units 1 and 2 circumferential welds when compared to the limiting CB&I vessel circumferential weld at 64 EFPY. The staff confirmed that the limiting LGS Units 1 and 2 circumferential welds are projected to have less irradiation damage than the limiting CB&I plant-specific case. Therefore, the applicant's evaluation is acceptable.

For the second criterion, the applicant stated in LRA Section 4.2.4 that LGS Units 1 and 2 will use the same procedures and training in the period of extended operation that has been the practice during the original licensing period. Although this is not specifically related to any time-limited parameter subject to a TLAA review, the staff determines that continued implementation of operator training and the use of procedures limiting the frequency of cold overpressure events meets the second criterion in the FSER for BWRVIP-05.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(iii), that the TLAA associated with the circumferential weld inspection will be adequately managed for the period of extended operation. Additionally, the applicant's analysis meets the acceptance criteria in SRP-LR Section 4.2.2.1.4 because the applicant plans to reapply for relief under 10 CFR 50.55a(a)(3).

4.2.6.3 UFSAR Supplement

LRA Section A.4.2.6 provides the UFSAR supplement summarizing the TLAA evaluation of the RPV circumferential welds inspection. The staff reviewed LRA Section A.4.2.6, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of the RPV circumferential welds inspection, as required by 10 CFR 54.21(d).

4.2.6.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the TLAA associated with the circumferential weld inspection will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.2.7 Reactor Pressure Vessel Reflood Thermal Shock

4.2.7.1 Summary of Technical Information in the Application

LRA Section 4.2.7 describes the applicant's TLAA for thermal shock on the RPV by reevaluating the generic fracture mechanics evaluation of the effects of a postulated loss of coolant accident (LOCA) on the structural integrity of a BWR. The LRA states that the generic analysis envelopes LGS and was based on BWR vessel material properties and 40 year assumed cumulative fluence.

The applicant modified the analysis to account for neutron embrittlement by substituting the limiting ART values for each unit after 57 EFPY. In addition, the applicant modified the analysis for the actual LGS RPV wall thickness, and the wall temperature at the 1/4T location was adjusted from 400 °F to 370 °F to ensure that the analysis bounds the temperature at which the maximum applied stress intensity factor (K_I) = 100 ksi-in$^{1/2}$ is applied. The applicant then calculated the limiting temperature where the material's resistance (K_{Ic}) is equal to 200 ksi-in$^{1/2}$ based on the limiting ART value for each unit. The applicant's evaluation showed that the RPV for LGS Unit 1 is safe from brittle fracture at any temperature above 178 °F and LGS Unit 2 at any temperature above 206 °F. These temperatures compare to the actual RPV temperature of 370 °F for the 1/4T location in the analysis.

The applicant dispositioned the RPV reflood thermal shock analysis in accordance with 10 CFR 54.21(c)(1)(ii), that the analysis has been projected to the end of the period of extended operation.

4.2.7.2 Staff Evaluation

The staff reviewed the applicant's TLAA for thermal shock to verify, pursuant to 10 CFR 54.21(c)(1)(ii), that the analyses have been projected to the end of the period of extended operation. This review was implemented consistent with SRP-LR Section 4.7.3.

The staff reviewed LRA Sections 4.2.3 and 4.2.7 to verify the fracture toughness of the limiting beltline materials. The staff noted that the input data to the calculation of the limiting ART used in the reevaluation of the core reflood thermal shock analysis were consistent with corresponding input values used to project ART at 57 EFPY for each unit in the recent power uprate amendment (approved April 8, 2011), and thus, are consistent with the CLB for Units 1 and 2. Based on the wide margin between the reported limiting temperatures for safe operation for each unit and temperature associated with the maximum K_I, the staff determined that brittle fracture of the LGS Units 1 and 2 RPVs is unlikely caused by reflood thermal shock following a LOCA during the period of extended operation. The applicant's decision to decrease the temperature for the analyses from 400 °F to 370 °F provides an extra margin of safety in this analysis.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the reflood thermal shock analyses for the LGS Units 1 and 2 RPVs have been projected to the end of the period of extended operation.

4.2.7.3 UFSAR Supplement

LRA Section A.4.2.7 provides the UFSAR supplement summarizing the reflood thermal shock analyses TLAA evaluations. The staff reviewed LRA Section A.4.2.7, consistent with the review procedures in SRP-LR Section 4.2.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.2.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA evaluation of the reflood thermal shock analyses TLAA evaluations, as required by 10 CFR 54.21(d).

4.2.7.4 Conclusion

On the basis of its review, the staff concludes that the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(ii), that the RPV reflood thermal shock analyses have been projected to the end of the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.3 <u>Metal Fatigue</u>

4.3.1 ASME Code Section III, Class 1 Fatigue Analyses

4.3.1.1 Summary of Technical Information in the Application

LRA Section 4.3.1.describes the applicant's TLAA for ASME Code Section III, Class 1 fatigue analyses. The LRA states that the RPV and RCPB piping and components were designed in accordance with the ASME Code Section III, Class 1 design requirements. In addition, fatigue analyses were prepared for these components to determine the effects of cyclic loadings resulting from changes in system temperature, pressure, and seismic loading cycles. These fatigue analyses evaluated an explicit number and type of transients that were postulated in the design specifications to envelope the number of occurrences possible during the 40-year design life of the plant. Since these fatigue usage factors are part of the CLB and originally based on 40-year assumptions, they have been identified as TLAAs requiring evaluation for the period of extended operation.

The applicant dispositioned the TLAA for ASME Code Section III, Class 1 fatigue analyses in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of fatigue on the intended functions of components analyzed in accordance with ASME Code Section III, Class 1 requirements will be managed by the Fatigue Monitoring program for the period of extended operation.

4.3.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the ASME Code, Section III, Class 1 fatigue analyses and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3, which states that the reviewer should verify that the applicant has identified the appropriate program as described and evaluated in the Generic Aging Lessons Learned Report (GALL Report) and included an assessment of the TLAA information against relevant design basis and CLB information.

The LRA states that ASME Code, Section III, Class 1 fatigue analyses include the stress reports for the RPV, RCPB piping and components, including ASME Code, Section III, Class 1 valves, which are based on the same 40-year design transients listed in UFSAR Table 3.9-2, "Plant Events," for the RPV and UFSAR Table 5.2-9, "RCPB Operating Thermal Cycles," for the RCPB components. The LRA states each ASME Code, Section III, Class 1 fatigue analysis demonstrates that the component has a cumulative usage factor (CUF) value that does not exceed the design Code limit of 1.0.

The applicant stated that it used transient cycle monitoring data from the Fatigue Monitoring program to develop the 60-year transient projections shown in LRA Table 4.3.1-1 and LRA Table 4.3.1-2 for LGS Units 1 and 2, respectively. The staff noted that these tables contain cumulative numbers of cycles through January 2011, and the numbers of cycles projected to occur over 60 years. Finally, the current design cycle limit for the monitored transients was also provided, which is the number of cycles analyzed in the ASME Code, Section III, Class 1 fatigue analyses.

LRA Table 4.3.1-1 indicates that the cumulative cycles of "Startup" (Transient No. 3) and "Shutdown" (Transient No. 10) is 52 and 50, respectively, for LGS Unit 1. In addition, the table indicates that there were 14 occurrences of "Scram – Turbine-Generator Trip, Feedwater Stays ON, Isolation Valves Stay OPEN" (Transient No. 9a) and 47 occurrences of "Scram-all other Scrams" (Transient No. 9b).

LRA Table 4.3.1-2 indicates that the cumulative cycles of "Startup" (Transient No. 3) and "Shutdown" (Transient No. 10) are 35 and 33, respectively, for LGS Unit 2. In addition, this table indicates that there were 14 occurrences of "Scram – Turbine-Generator Trip, Feedwater Stays ON, Isolation Valves Stay OPEN" (Transient No. 9a) and 35 occurrences of "Scram-all other Scrams" (Transient No. 9b).

It was not clear to the staff why there were more occurrences of the "Startup" transient than the "Shutdown" transient for each unit. The staff also noted that, for LGS Unit 1, there are 61 scrams compared to 50 occurrences of the "Shutdown" transient, and that, for LGS Unit 2, there are 39 scrams as compared to 33 occurrences of the "Shutdown" transient. The staff noted that the baseline information for these transients is important because the projections are used to support the TLAA dispositions in LRA Section 4. By letter dated January 31, 2012, the staff issued RAI 4.3-1 requesting the applicant to clarify these discrepancies.
In its response, dated February 29, 2012, the applicant stated there are two reasons for the discrepancy between the Startup and Shutdown transients. The first reason is that as of the date the data were obtained in January 2011, both units were operating, which accounted for one additional startup as compared to shutdowns. The other reason is that each unit experienced an Emergency Scram – Single Relief Valve or Safety Valve Blowdown transient (Transient No. 14d), which is a more severe transient that transitions the reactor from operating temperature to cold shutdown. The applicant stated that Transient No. 14d, recorded since the event, was more severe than a Shutdown transient and no Shutdown transient was required to be recorded. The staff finds it reasonable that a Shutdown transient was not recorded because the more severe transient that brought the reactor from operating temperature to cold shutdown was recorded. Thus, the staff concluded that the listed occurrences of the Startup transient are consistent with the listed occurrences of the Shutdown Transients and one occurrence of the Emergency Scram transient.

The applicant stated that the reason for the discrepancy between reported Scram transients and Shutdown transients is that these events do not necessarily correlate with each other. Scram events transition the plant from power operation to hot standby, which is generally a short period during which preparations are made for further transitioning to cold shutdown. The applicant explained that if a transition to cold shutdown is performed after a Scram, then one Scram transient is recorded and one Shutdown transient is recorded. However, there are occasions when the reactor is placed in hot standby with the intention that it will return to normal power operation after a short period of time rather than to cold shutdown. The applicant explained that one Scram transient is recorded but no Shutdown transient is recorded in such cases where the reactor is returned to power operation directly from hot standby. Also, for planned outages, the plant may transition from power operations to cold shutdown by manual control rod insertion without initiating a scram, in which case, one Shutdown transient is recorded and no Scram transient is recorded.

Based on its review, the staff finds the applicant's response to RAI 4.3-1 acceptable because the applicant clarified the discrepancy between the cumulative Startup and Shutdown transients and between the cumulative Shutdown and Scram transients. In addition, the staff finds the applicant's response acceptable because the fatigue monitoring results are consistent with the actual transients that occurred at the plant, which provide an accurate baseline count for the Fatigue Monitoring program to ensure the validity of the metal fatigue TLAAs during the period of extended operation. The staff's concern described in RAI 4.3-1 is resolved.

The staff reviewed UFSAR Table 3.9-1, Section T "General Electric Criteria for NSSS Piping," and noted that it indicates that the "Turbine Stop Valve Closure" transient is an upset transient with a design of 120 cycles. UFSAR Table 3.9-1, Section T also indicates that the "Relief Valve Lift Cycles" transient is an upset transient with a design of 34,200 cycles. Furthermore, UFSAR Figure 3A-394 indicates that "Chugging" is a transient used as an input into the fatigue analysis of MSRV downcomers with a design of 3,000 cycles.

These transients were not included in LRA Tables 4.3.1-1 and 4.3.1-2; therefore, it was not clear to the staff whether these transients have been used as inputs for the TLAAs discussed in LRA Section 4. Depending on the disposition of these TLAAs, if these transients were used as inputs, the staff noted that the type of information necessary to justify the disposition will differ. By letter dated January 31, 2012, the staff issued RAI 4.3-2 requesting the applicant to identify the TLAAs that used these transients and confirm these transients were monitored since initial plant startup for each unit.
In its response, dated February 29, 2012, the applicant stated that the TLAAs that use these transients are the fatigue analyses for the RPV, RPV internals and supports, and ASME Code, Section III, Class 1 piping. The fatigue analyses for the RPV and ASME Code, Section III, Class 1 piping that are evaluated in LRA Section 4.3.1 are dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), crediting the Fatigue Monitoring program. Furthermore, the RPV internals fatigue TLAAs that are evaluated in LRA Section 4.3.4 that are also dispositioned in accordance with 10 CFR 54.21(c)(1)(iii), crediting the Fatigue Monitoring program, as amended in response to RAI 4.3-10.

The applicant explained that the transient characterized in UFSAR Table 3.9-1 as "Turbine Stop Valve Closure," is an event included within the definition of Transient No. 9a – "Scram, Turbine Generator Trip, Feedwater Stays ON, Isolation Valves Stay OPEN," which has a design limit of 40 events. The applicant stated that the Fatigue Monitoring program has monitored these events since initial plant startup for each unit and limits the number of turbine stop valve closure events to 40, and LRA Tables 4.3.1-1 and 4.3.1-2 show that the 60-year projection for Transient No. 9a does not exceed the 40-year design limit. Since the "Turbine Stop Valve Closure" transient is incorporated by definition into Transient No. 9a, the staff finds it appropriate that the Fatigue Monitoring program can and will continue to manage Transient No. 9a through the period of extended operation.

The applicant stated that UFSAR Table 3.9-1, Section T includes "Relief Valve Lift Cycles" (at 3 cycles per actuation) - 34,200 cycles, which equates to 11,400 MSRV actuations. However, the downcomers and MSRV discharge piping were analyzed for 1,100 MSRV actuations, which is more limiting and is the limit being imposed in the Fatigue Monitoring program for MSRV actuations. The staff noted that the Fatigue Monitoring program has an existing enhancement to monitor additional transients that are significant contributors to fatigue usage. Therefore, the staff finds that the MSRVs will not exceed 11,400 actuations, as specified in UFSAR Table 3.9-1, Section T for "Relief Valve Lift Cycles" through the period of extended operation, because the applicant's program is monitoring this transient and has a lower cycle limit of 1,100 MSRV actuations.

The applicant stated that the chugging cycles are loads that result from various modes of steam condensation at the downcomer vent ends following a LOCA. The staff noted that as a result of RAIs 4.6.8-1 and 4.6.8-2, the applicant amended LRA Tables 4.3.1-1 and 4.3.1-2 to include Transient No. 18, Faulted Condition – Pipe Rupture and Blowdown, which corresponds to a

LOCA. In addition, this transient is monitored by the Fatigue Monitoring program and the monitoring results show that a LOCA event has not occurred in either unit. Since both units have not experienced a LOCA event, which would result in chugging cycles, the staff finds the applicant's determination that no chugging cycles have occurred to date is reasonable.

Based on its review, the staff finds the applicant's response to RAI 4.3-2 acceptable because the applicant clarified the analyses that assumed the turbine stop valve closure, relief valve lift cycles and chugging transients, and the Fatigue Monitoring program, when enhanced, will monitor these transients to ensure the fatigue analyses that used these transients will remain valid during the period of extended operation. The staff's concern described in RAI 4.3-2 is resolved.

LRA Table 4.3.1-1 indicates that the "Adjusted 60-year Projected Cycles" are two cycles for the "Core Spray" and the "Low-Pressure Coolant Injection" transients for LGS Unit 1. In addition, LRA Table 4.3.1-2 also provides the same information about these transients for LGS Unit 2. The staff noted that the "Design Cycle Limits" for these two transients are not provided in LRA Tables 4.3.1-1 and 4.3.1-2 and the applicant did not explain or justify why the design cycle limits are not needed. By letter dated January 31, 2012, the staff issued RAI 4.3-3 requesting the applicant to identify the TLAAs that used these transients and to confirm that these transients were monitored since initial plant startup for each unit.

In its response, dated February 29, 2012, the applicant stated that LRA Tables 4.3.1-1 and 4.3.1-2 include a collection of emergency core cooling system/reactor core isolation cooling (ECCS/RCIC) and SLC injections that includes cycles for CS and LPCIs and are not thermal transients used as inputs in fatigue TLAAs. The applicant indicated that these events are a result of the "numbered" thermal transients provided in LRA Tables 4.3.1-1 and 4.3.1-2. The ECCS/RCIC injections are monitored separately to ensure that NRC reporting requirements are met regarding fatigue usage of RPV nozzles resulting from ECCS and RCIC injections. The staff noted from its audit that these transients are associated with Technical Specification 3.5.1, "Action," Subsection f, which states that in the event an ECCS system is actuated and injects water into the RCS, a special report shall be prepared and submitted to the NRC. The applicant also stated that since the ECCS/RCIC injections are not transient events used as inputs in the fatigue analyses, LRA Tables 4.3.1-1 and 4.3.1-2 are revised to remove this information for clarity.

Based on its review, the staff finds the applicant's response to RAI 4.3-3 and the removal of these transients from LRA Table 4.3.1-1 and 4.3.1-2 acceptable because these ECCS/RCIC and SLC injections transients were not used as inputs to existing fatigue analyses and are only a result of monitored thermal transients. In addition, the staff finds it acceptable that these ECCS/RCIC and SLC injections transients are not specifically monitored by the Fatigue Monitoring program because the applicant is required to keep track of the actuation of ECCS (RCIC, HPCI, LPCI, and CS) and injection of water into the RCS per Technical Specification 3.5.1, "Action," Subsection f. The staff's concern described in RAI 4.3-3 is resolved.

In its response to RAI 4.3-10.2, provided by letter dated June 19, 2012, regarding the staff's concern related to reactor vessel internals components, the applicant stated that fatigue exemptions (or fatigue waivers) for ASME Code, Section III, Class 1 components are TLAAs because the exemptions meet all six TLAA criteria defined in 10 CFR 54.3. The applicant stated that Criterion 3 is met because the time-limited assumptions are based upon an evaluation of the thermal and pressure transients defined for 40 years in the design specifications for ASME Code, Section III, Class 1 components. The applicant revised LRA Sections 4.3.1 and 4.3.4 to clarify that all fatigue exemptions have been identified as TLAAs and are managed by the Fatigue Monitoring program. The applicant also stated that UFSAR supplement Sections A.4.3.1 and A.4.3.4 were revised with conforming changes. The staff's review of the applicant's respond to RAI 4.3-10.2 is documented in SER Section 4.3.4.2.

LRA Section 4.3.1 also states that the projections show that the current design cycle limits will not be exceeded during 60 years of plant operation for LGS Units 1 and 2; therefore, none of the transient types are expected to be exceeded during the period of extended operation and the ASME Code, Section III, Class 1 fatigue analyses will remain valid for the period of extended operation. The staff noted that since the applicant's assumption relies on the fact that the rate of cycle occurrence in the future will not exceed the average rates of occurrence of past cycles, the applicant trended each transient projection graphically to determine if recent rates of occurrence could be higher than the overall average rates of occurrence. The applicant demonstrated, through such trending, that recent transient occurrence rates are bounded by the average occurrence rates. However, the staff noted that in order to ensure that this conclusion and basis remains valid for transient projections and trending, the Fatigue Monitoring program will be used to monitor and track transient cycle occurrences through the end of the period of extended operation to ensure that these limits are not exceeded.

The staff's review of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting ASME Code, Section III, Class 1 fatigue analysis. In addition, the program requires comparison of the actual event parameters to the applicable design transient definitions to assure the actual transients are bounded by the applicable design transients. If a transient approaches an action limit, which the applicant has set to 80 percent of the cycle limit, corrective actions are triggered for repair, replacement, or reanalysis of the component, in accordance with its Fatigue Monitoring program. The staff determined that these characteristics of the Fatigue Monitoring program are consistent with GALL Report AMP X.M1. The staff noted that the applicant's method for managing these ASME Code, Section III, Class 1 fatigue analyses is conservative because corrective actions are initiated when one transient type approaches 80 percent of the cycle limit, when typically a Class 1 fatigue analysis assumes contributions to fatigue usage from more than one transient type.

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the components analyzed in accordance with ASME Code Section III, Class 1 requirements will be adequately managed by the Fatigue Monitoring program for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant is crediting its Fatigue Monitoring program, which the staff determined, as documented in SER Section 3.0.3.2.20, is consistent with GALL Report AMP X.M1, to manage metal fatigue by monitoring transient occurrences to ensure that the assumptions in the ASME Code, Section III, Class 1 fatigue analyses and fatigue exemptions, remain valid during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.1.3 UFSAR Supplement

LRA Section A.4.3.1, as amended by letter dated June 19, 2012, provides the UFSAR supplement summarizing the metal fatigue and fatigue exemptions TLAAs for ASME Code, Section III, Class 1 components. The staff reviewed LRA Section A.4.3.1, consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAAs.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the ASME Code, Section III, Class 1 metal fatigue and fatigue exemptions TLAAs, as required by 10 CFR 54.21(d).

4.3.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(iii), that effects of fatigue for ASME Code, Section III, Class 1 components will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.3.2 ASME Code Section III, Class 2 and 3 and ANSI B31.1 Allowable Stress Calculations

4.3.2.1 Summary of Technical Information in the Application

LRA Section 4.3.2 describes the applicant's TLAA for ASME Code Section III, Class 2 and 3 and ANSI B31.1 allowable stress calculations. The LRA states that the piping that was designed in accordance with ASME Code Section III, Class 2 or 3 design rules or ANSI B31.1 Piping Code design rules is not required to have an explicit analysis of cumulative fatigue usage, but cyclic loading is considered in a simplified manner in the design process. The LRA further states that these codes first require prediction of the overall number of thermal and pressure cycles expected during the 40-year lifetime of these components; then a stress range reduction factor is determined for the number of cycles. The LRA states that these are considered to be implicit fatigue analyses since they are based upon cycles anticipated for the life of the component. The applicant evaluated this TLAA for those for the ASME Code Section III, Class 2 and 3 and ANSI B31.1 systems connected to ASME Code Section III, Class piping, and are affected by the same operational transients and for the remaining systems that are affected by different thermal and pressure cycles.

The applicant dispositioned the metal fatigue TLAA for ASME Code Section III, Class 2 and 3 and ANSI B31.1 allowable stress calculations in accordance with 10 CFR 54.21(c)(1)(i) to demonstrate that the analysis remains valid during the period of extended operation.

4.3.2.2 Staff Evaluation

The staff reviewed the applicant's metal fatigue TLAA for the ASME Code Section III, Class 2 and 3, and ANSI B31.1 allowable stress calculations and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.2.1, which states that relevant information in the TLAA, operating plant transient history, design basis, and CLB is reviewed to verify that the maximum allowable stress range values for the existing fatigue analysis remain valid for the period of extended operation and that the allowable limit for full thermal range transients will not be exceeded during the period of extended operation.

LRA Section 4.3.2 states that for the ASME Code Section III, Class 2 and 3, and ANSI B31.1 systems that are connected to ASME Code Section III, Class 1 piping, and are affected by the same operational transients, the 60-year cycle projections demonstrate that the total number of thermal and pressure cycles of all of the transient types added together will not exceed 7,000 cycles during the period of extended operation. Therefore, the stress range reduction factor will not change and the TLAAs will remain valid for the period of extended operation. The applicant stated this includes the applicable portions of the following systems: Residual Heat Removal (RHR), CS, Reactor Core Isolation Cooling (RCIC), High-Pressure Coolant Injection (HPCI), Reactor Water Cleanup, Control Rod Drive (CRD), Main Steam, Main Turbine, Extraction Steam, Feedwater, Condenser and Air Removal, and Radwaste.

The applicant also stated in LRA Section 4.3.2, that for the remaining systems affected by different thermal and pressure cycles, an operational review was performed that also concluded that the total number of cycles, projected for 60 years, will not exceed 7,000 cycles for the fire protection, EDG, and auxiliary steam systems. Systems with operating temperatures below specified thresholds were determined to have low numbers of equivalent full temperature cycles since the fluid temperature changes are small. Therefore, since the stress range reduction factors originally selected for the components in all of these systems remain applicable, the applicant determined that the TLAAs remain valid for the period of extended operation.

The staff noted that LRA Section 4.3.2 did not provide information regarding the accumulated number of occurrences and the 60-year projected number of occurrences for the aforementioned remaining systems that are affected by different thermal and pressure cycles. Therefore, the staff could not verify the adequacy of the disposition in accordance with 10 CFR 54.21(c)(1)(i). Furthermore, UFSAR Section A.4.3.2 indicates that the TLAA will be adequately managed for the period of extended operation by the Fatigue Monitoring program in accordance with 10 CFR 54.21(c)(1)(iii), which is different from the disposition identified in LRA Section 4.3.2. By letter dated January 31, 2012, the staff issued RAI 4.3-4 requesting the applicant to identify the "different thermal and pressure cycles" referenced in the LRA and to identify the accumulated number of occurrences for each transient. In addition, the staff requested that the applicant clarify the discrepancy in the disposition for the TLAA.

In its response dated February 29, 2012, the applicant stated the ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems not connected to Class 1 piping that were evaluated include the following:

- The diesel engine exhaust piping from the diesel-driven fire pump and backup diesel-driven fire pump in the fire protection system. The engine exhaust piping from the diesel-driven fire pumps experiences a thermal cycle each time the engine starts and is later shutdown.

- The EDGs exhaust piping in the emergency diesel generator system. The diesel generator engine exhaust piping experiences a thermal cycle each time the engine starts and is later shutdown.
- The piping from the auxiliary boilers used for plant heating steam in the auxiliary steam system. The portions of the plant heating steam piping within the scope of license renewal experience a thermal cycle each time the plant heating steam system is placed in service and is later shutdown.

The staff noted that each of these systems have 60-year cycle projections based on estimated operational cycles rather than actual counts for the number of cycles. The staff's evaluation of each of the 60-year cycle projections based on estimated operational cycles is discussed below.

The applicant explained that the diesel-driven fire pump and backup diesel-driven fire pump is common for both units and these engine runs were not monitored since initial plant startup, but the number of cycles has been estimated based on operational history. The diesel-driven fire pump engine is normally not in service and the engine is only operated during surveillance testing and in response to a fire when the motor-driven pump does not maintain fire water header pressure.

In addition, the backup diesel-driven fire pump engine is normally not in service and the engine is only operated during surveillance testing and in response to a fire when both the motor driven pump and diesel-driven pump do not maintain fire water header pressure. The applicant estimated that these engines run no more than two times per year to maintain fire water header pressure. The applicant also stated that it operated an average of 13 times per year during surveillance testing. Based on an average of 15 cycles per year, the applicant determined that the diesel-driven fire pump exhaust piping will experience approximately 975 thermal cycles through the period of extended operation for LGS Unit 2 (65 years total). The staff noted that there are less than 65 years between the Operating License of Unit 1, granted in August 1985 and the end of the period of extended operation of Unit 2, in June 2049. The staff noted that the estimate of 975 thermal-cycles is reasonable for LGS because the pump is common for both units and the estimate covered the total time span of 65 years of the operations of both units. The staff finds the applicant's estimated number of cycles for the diesel-driven fire pump and backup diesel-driven fire pump to be reasonable because it is based on routine usage to maintain header pressure or scheduled testing throughout a year. In any event, the number of expected cycles through the period of extended operation for both units is expected to be no more than 14 percent of the 7,000 allowable cycles; therefore, there is a significant margin to account for unanticipated cycles for the diesel-driven fire pump and backup diesel-driven fire pump.

The applicant explained that the EDG engine runs have not been monitored since initial plant startup, but the number of cycles has been estimated based on operational history. The engines are normally not in service, but they are operated in response to a LOCA or a loss of offsite power. Since these events occur very infrequently, the applicant estimated that each EDG is run no more than once per year in response to these events. In addition, a review of surveillance test frequencies determined that each EDG is run an estimated 22 times per year for testing. The applicant's review of the system manager's informal log of actual EDG runs revealed that the average number of runs per EDG in 2010 and 2011 was 19 per year, thus, confirming that 22 cycles per year is a conservative estimate for annual EDG surveillance test runs. Based on an average of 23 cycles per year, the applicant determined that each EDG will experience approximately 1,380 thermal cycles though 60 years of operation. The staff finds the applicant's estimated number of cycles for the EDG runs to be reasonable because it is based on a conservative estimate of annual routine surveillance test runs and unanticipated response to a LOCA or a loss of offsite power, which are infrequent events. In any event, the number of expected cycles through the period of extended operation is expected to be no more than 20 percent of the 7,000 allowable cycles; therefore, the staff finds that there is a significant margin to account for unanticipated cycles for the EDGs.

The applicant explained that the auxiliary steam system is common for both units and the thermal cycles have not been monitored since initial plant startup, but the number of cycles has been estimated based on operational history. The auxiliary steam system is typically in service for the entire heating system from fall until spring each year; however, the system may be removed from service during each heating season to perform maintenance or during periods of warm weather when the plant heating system is not needed. The applicant stated that based on an estimated average of 5 cycles per year, the auxiliary steam system piping will experience approximately 325 thermal cycles through the period of extended operation for LGS Unit 2 (65 years total). The staff noted that the estimate of 325 thermal-cycles is reasonable for LGS because the system is common for both units and the estimate covered the total time span of 65 years of the operations of both units. The staff finds the applicant's estimated number of cycles for the auxiliary steam system to be reasonable because it is based on routine cycling throughout a year. In any event, the number of expected cycles through the period of extended operation for both units is expected to be no more than 5 percent of the 7,000 allowable cycles; therefore, there is a significant amount of margin to account for unanticipated cycles for the auxiliary steam system piping.

The applicant clarified that the fatigue TLAAs for the ASME Code Section III, Class 2 and 3, and ANSI B31.1 piping systems not connected to Class 1 piping systems have been demonstrated to remain valid for the period of extended operation in accordance with 10 CFR 54.21(c)(1)(i). The staff noted that this is a separate disposition from the one for the ASME Code Section III, Class 2 and 3, and ANSI B31.1 connected to the Class 1 piping, which are managed by the Fatigue Monitoring program in accordance with 10 CFR 54.21(c)(1)(iii). LRA Section 4.3.2 and UFSAR supplement Section A.4.3.2 are revised to include two TLAA dispositions; one for the ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems connected to Class 1 piping, and another one for ASME Code, Section III, Class 2 and 3, and B31.1 piping systems that are not connected to Class 1 piping.

Based on its review, the staff finds the applicant's response to RAI 4.3-4 acceptable because the applicant explained the "different thermal and pressure cycles" associated with ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems that are not connected to ASME Code, Section III, Class 1 piping and the applicant justified that the cycles for these systems will not exceed the 7,000 allowable cycles through the period of extended operation, as described above. The staff's review of the applicant's disposition for the TLAAs associated with ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems are discussed below. The staff's concern described in RAI 4.3-4 is resolved.

The staff reviewed LRA Section 4.3.2.2, as amended by letter dated February 29, 2012, the response to RAI 4.3-4, and the TLAA for ASME Code, Section III, Class 2 and 3, and ANSI

B31.1 piping systems that are connected to ASME Code, Section III, Class 1 piping to verify that in accordance with 10 CFR 54.21(c)(1)(iii), the effects of fatigue will be adequately managed for the period of extended operation.

Since the ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems are connected to ASME Code, Section III, Class 1 piping, the staff finds it reasonable to conclude that the same operational transients analyzed for the ASME Code, Section III, Class 1 piping systems similarly affect the connected ASME Code, Section III, Class 2 and 3, and B31.1 portions of the piping systems. The staff noted that the Fatigue Monitoring program monitors and tracks the number of critical thermal, pressure, and seismic transients listed in LRA Table 4.3.1-1 (LGS Unit 1) and LRA Table 4.3.1-2 (LGS Unit 2). In addition, the program requires comparison of the actual event parameters (pressure, temperature, or flow rate changes) to the applicable design transient definitions to assure the actual transients are bounded by the applicable design transients. The staff noted that the applicant's program ensures that the 7,000 limit on the number of full temperature cycles will not be exceeded through the period of extended operation without the applicant taking corrective actions.

The staff finds the applicant has demonstrated in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems connected to ASME Code, Section III, Class 1 piping will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP–LR Section 4.3.2.1.2.3 because the Fatigue Monitoring program tracks the number of design basis transients that will occur through the period of extended operation and includes action limits and corrective actions that will ensure that the assumptions made in these ASME Code, Section III, Class 2 and 3, and ANSI B31.1 fatigue analyses for systems connected to ASME Code, Section III, Class 1 piping will not be exceeded during the period of extended operation.

The staff reviewed LRA Section 4.3.2.2, as amended by letter dated February 29, 2012, and the TLAA for ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems that are not connected to Class 1 piping to verify in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

As discussed above in the staff's review of the applicant's response to RAI 4.3-4, the staff determined the following: for the fire protection system, the number of expected cycles through the period of extended operation for both units is expected to be no more than 14 percent of the 7,000 allowable cycles, which leaves significant margin to account for unanticipated cycles for the diesel-driven fire pump and backup diesel-driven fire pump; for the EDG system the number of expected cycles through the period of extended operation is expected to be no more than 20 percent of the 7,000 allowable cycles, which leaves significant margin to account for unanticipated cycles for the EDGs; and for the auxiliary steam system piping the number of expected cycles through the period of extended operation for both units is expected to be no more than 5 percent of the 7,000 allowable cycles, which leaves significant margin to account for unanticipated cycling of the system.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAAs of ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems that are not connected to Class 1 piping, remain valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 because the projected total number of full thermal range transients over the period of extended operation for ANSI B31.1 and ASME Code, Section III, Class 2 and 3, piping does not exceed the 7,000-cycle limit, with significant margin to account for unanticipated cycling of the systems.

4.3.2.3 UFSAR Supplement

LRA Section A.4.3.2, as amended by letter dated February 29, 2012, provides the UFSAR supplement summarizing the TLAA for ASME Code Section III, Class 2 and 3, and ANSI B31.1 allowable stress calculations. The staff reviewed LRA Section A.4.3.2, consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of ASME Code Section III, Class 2 and 3, and ANSI B31.1 allowable stress calculations, as required by 10 CFR 54.21(d).

4.3.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, as required by 10 CFR 54.21(c)(1)(i), that the fatigue analyses of ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems connected to Class 1 piping remain valid for the period of extended operation. The staff also concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue for ASME Code, Section III, Class 2 and 3, and ANSI B31.1 piping systems connected to Class 1 piping will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.3.3 Environmental Fatigue Analyses for RPV and Class 1 Piping

4.3.3.1 Summary of Technical Information in the Application

LRA Section 4.3.3.describes the applicant's analyses to address EAF for the RPV and ASME Code Class 1 piping. The applicant stated that environmental fatigue calculations were performed for each component location listed in NUREG/CR-6260 for the newer-vintage BWR. In order to ensure that any other locations that may not be bounded by the NUREG/CR-6260 locations were evaluated, environmental fatigue calculations were performed for each RPV component location that has a reported CUF value in the stress report and for each ASME Code Class 1 RCPB piping system in each unit. These calculations were performed for the limiting location for each material within the component or system that is in contact with reactor coolant. LRA Table 4.3.3-1 shows the results from the environmental fatigue calculations for the RPV components and LRA Table 4.3.3-2 shows the results for the ASME Code, Section III, Class 1 RCPB systems.

The applicant dispositioned the EAF analyses for the RPV and ASME Code, Section III, Class 1 RCPB piping in accordance with 10 CFR 54.21(c)(1)(iii) to demonstrate that the effects of EAF on the intended functions of the analyzed components will be managed by the Fatigue Monitoring program for the period of extended operation.

4.3.3.2 Staff Evaluation

The staff noted that the applicant addressed the effects of EAF, consistent with the guidance in the SRP-LR and the staff's recommendations for resolving Generic Safety Issue No. 190 (GSI-190), dated December 26, 1999. The staff also noted that, consistent with Commission Order No. CLI-10-17, dated July 8, 2010, the evaluations associated with EAF do not fall within the definition of TLAA in 10 CFR 54.3(a) because these evaluations are not in the CLBs of LGS Units 1 and 2. Nevertheless, the applicant has credited its Fatigue Monitoring program to manage the effects of EAF; therefore, the staff reviewed LRA Section 4.3.3 and the evaluations for EAF to verify, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of EAF will be adequately managed for the period of extended operation.

The staff reviewed the applicant's EAF analyses for the RPV and ASME Code, Section III, Class 1 RCPB piping and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.3, which provides guidance for the reviewer to verify that the applicant has addressed EAF as part of an AMP formulated in support of license renewal. In addition, the SRP-LR provides guidance for verifying that the critical components evaluated for EAF include a sample of high-fatigue usage locations and have applied environmental fatigue life correction factor (F_{en}) values, which are calculated with the recommended sets of formulae in NUREG/CR-5704, NUREG/CR-6583, and NUREG/CR-6909.

LRA Table 4.3.3-1 provides the following information for the in-core housing penetration: the ASME Code based 60-year CUF is 0.108; the NUREG/CR-6909 based 60-year CUF is 0.140; and the 60-year CUF_{en} is 0.83. During its audit, the staff noted that the applicant's basis documents contained different CUF and CUF_{en} values than the values in LRA Table 4.3.3-1. By letter dated January 31, 2012, the staff issued RAI 4.3-5 requesting the applicant to clarify the discrepancy between the values presented in LRA Table 4.3.3-1 and its basis documents and to confirm that the remaining values in LRA Table 4.3.3-1 are accurate.

In its response dated February 29, 2012, the applicant revised LRA Table 4.3.3-1 with the following corrected values for in-core housing penetration for both units: the correct node location is 152, the ASME Code CUF is 0.181, the NUREG/CR-6909 CUF is 0.240, the F_{en} value is 2.42, and the CUF_{en} is 0.581. The applicant stated that the results from a revised environmental fatigue analysis for the CS nozzle forging in each unit is included in the revised LRA Table 4.3.3-1 and that additional information associated with this revision is in its response to RAI 4.3-9. The staff's review of the applicant's response to RAI 4.3-9 is documented elsewhere in this SER section. The applicant confirmed that the remaining values in Table 4.3.3-1 are accurate.

The staff finds the applicant's response to RAI 4.3-5 acceptable because LRA Table 4.3.3-1 was revised to accurately represent the information from the applicant's basis documents and calculations. The staff's concern described in RAI 4.3-5 is resolved.

In the applicant's submittal dated March 25, 2010, "Request for License Amendment Regarding Measurement Uncertainty Recapture Power Uprate," the applicant provided NEDO-33484, Revision 0, "Safety Analysis Report for Limerick Generating Station Units 1 & 2 Thermal Power

Optimization." Table 3-7 of this report provides 40-year CUF values for the CS nozzle, LPCI nozzle, and RPV support skirt and feedwater nozzles. The staff noted that the ASME Code CUF values in LRA Table 4.3.3-1 for these components are different from those in Table 3-7 of NEDO-33484, Revision 0. The LRA did not explain why these values are different in the two documents. By letter dated January 31, 2012, the staff issued RAI 4.3-9 requesting the applicant to reconcile and justify the differences in the CUF values.

In its response dated February 29, 2012, the applicant provided an explanation for the difference in CUF values between the two documents for the CS nozzle, LPCI nozzle, and RPV support skirt and feedwater nozzles. The staff's review of each explanation is documented below.

For the LPCI nickel alloy nozzle safe end, the applicant stated that the CUF value of 0.79 shown in Table 3-7 of NEDO-33484, was based on the associated power-uprate evaluation. The ASME Code CUF value of 0.504 shown in LRA Table 4.3.3-1 is the revised CUF value from the environmental fatigue analysis that was further refined from the power-uprate analysis with the ASME Code fatigue curve. The NUREG/CR-6909 CUF value of 0.420 and F_{en} value of 1.94 were determined using the fatigue curve and F_{en} formula, respectively, in NUREG/CR-6909. The staff noted that the applicant's use of the formulas and fatigue curves for nickel alloy components from NUREG/CR-6909 is consistent with the recommendation of GALL Report AMP X.M1.

For the feedwater nozzles, the applicant stated that the environmental fatigue analysis includes a new ASME Code Section III, NB-3200, fatigue analysis that includes an updated loads analysis that reduces the number of feedwater injections assumed during shutdown events from five cycles to one cycle. The applicant explained that this update more closely reflects the plant's actual feedwater system design; therefore, the new CUF value determined in the environmental fatigue analysis is lower than the value in the original design report as stated in UFSAR Table 3.6-8. The staff finds that the applicant's update for feedwater injections and associated refined calculation reasonable because it represents a more realistic CUF for 60 years of operation that is based on the actual plant operating practices at LGS Units 1 and 2.

The applicant stated that the location reported in LRA Table 4.3.3-1 for the support skirt (RPV shell ID location adjoining skirt) is for a wetted surface inside the vessel shell at the location where the support skirt attaches to the vessel. The applicant explained that the highest fatigue location documented in the NEDO-33484 report was at the bottom of the skirt that rests on the concrete, which is not in contact with reactor coolant. The staff noted that the applicant appropriately considered the corresponding inside surface location within the RPV for EAF when the analyzed outside support skirt location is not in contact with reactor coolant.

The applicant stated that the CUF value reported in the LRA for the CS nozzle forging was based upon the original RPV stress report and did not address changes to the nozzle forging CUF value provided in subsequent reanalyses. The applicant also stated that the environmental fatigue analysis has been revised to address the changes introduced in the later reanalyses, including new loads, however, since the previously analyzed location is on the outside surface of the nozzle forging that does not contact reactor coolant, the revised environmental fatigue analysis evaluated the inside surface location at the clad-to-base metal interface directly below the limiting outside surface location. The applicant stated that this location was selected to represent the wetted internal surface of the forging but takes no credit for the presence of the cladding. The staff noted that the applicant's February 29, 2012, response to RAI 4.3-5 revised the ASME Code CUF value for CS nozzle (forging) from 0.097 to 0.0016 in LRA Table 4.3.3-1. However, when considering the applicant's response that this location was not originally analyzed for fatigue, it was not clear to the staff what the value of 0.0016 represents. The staff also noted that for the CS piping in LRA Table 4.3.3-2, the difference in F_{en} values between LGS Units 1 and 2 is substantial, but the applicant did not provide the basis for the large difference. By letter dated April 17, 2012, the staff issued followup RAI 4.3-9.1 requesting the applicant to provide the basis for the ASME Code CUF value of 0.0016 for the CS nozzle (forging) in LRA Table 4.3.3-1 and to justify why the difference in F_{en} values for the CS piping between LGS Units 1 and 2.

In its response dated May 4, 2012, the applicant stated that the original RPV stress report evaluated the CS nozzle forging with a CUF value of 0.097 for node 22, located on the external surface of the nozzle. This report did not report a CUF value for node 17, located on the inside surface of the nozzle. However, it did report that the number of allowable cycles for node 17 is 300,000 cycles, based on the ASME Code fatigue curve. The report also showed that the total number of design cycles for this location is 485 cycles. During development of the environmental fatigue analysis for node 17, the original ASME CUF value was determined to be $485 \div 300{,}000 = 0.0016$. The staff finds this explanation of the CUF value acceptable because the cumulative usage factor is equal to the design number of cycles divided by the allowable cycles; thus the CUF value of 0.0016 is appropriate for node 17 of the CS nozzle forging.

In addition, the applicant stated that the F_{en} values for the LGS Unit 1 and LGS Unit 2 CS piping were each computed consistent with the NUREG/CR-6909 methodology. An individual F_{en} value was computed for each transient pairing within each analysis and the NUREG/CR-6909 F_{en} value reported in LRA Table 4.3.3-2 is a weighted average value determined by dividing the CUF_{en} value for the analysis by the NUREG/CR-6909 CUF value. The applicant further stated that the individual F_{en} values computed for LGS Unit 1 assume the worst-case value for strain rate of 0.0004 percent/second provided in NUREG/CR-6909, which the staff finds to be conservative, with a resulting average "6909 F_{en}" value of 4.36 and CUF_{en} value of 0.856. However, in the LGS Unit 2 analysis, the F_{en} value uses a computed strain rate value of 0.0484 percent/second, which is appropriate since this transient pair is associated with safety relief valve and operational basis earthquake (OBE) cycles; the average 6909 F_{en} value is 2.89 and the CUF_{en} value is 0.786. For LGS Unit 2, the staff finds this method to be appropriate because the applicant used the actual conditions to compute the strain rate value, rather than using the worst-case scenario outlined in NUREG/CR-6909.

The staff finds the applicant's responses to RAI 4.3-9 and 4.3-9.1 acceptable because the applicant justified the differences of the CUF values between LRA Table 4.3.3-1 and Table 3-7 of NEDO-33484, Revision 0, which the staff evaluated individually above, and reconciled the differences in CUF values for the CS nozzle (forging) and F_{en} values for the CS piping between Units 1 and 2. The staff concerns identified in RAI 4.3-9 and followup RAI 4.3-9.1 are resolved.

LRA Table 4.3.3-2 states that the CUF values of 0.3505 and 0.1056 for the reactor recirculation piping were calculated using the fatigue design curve in NUREG/CR-6909 for LGS Units 1 and 2, respectively. In addition, it states that the CUF values of 0.0211 and 0.0798 for the MSIV drains were calculated using the fatigue design curve in ASME Code, Section III for LGS Units 1 and 2, respectively. The staff noted that there is a difference of approximately a factor of three between the CUF values reported for these components between the two units; however, the

LRA did not explain the reason for the large difference. In addition, it is not clear to the staff why the nodal locations are different between the two units for CS piping, MSIV drains, MSIV drain and test, RCIC steam supply, head vent, and safeguard piping fill systems.

By letter dated January 31, 2012, the staff issued RAI 4.3-7 requesting the applicant to explain and justify the difference in reported CUF values for the reactor recirculation piping and MSIV drains between the two units. In addition, for each component in LRA Table 4.3.3-2 that indicated different nodal locations between the two units, the staff requested the applicant to describe the configuration and justify the difference between the two units.

In its response dated February 29, 2012, the applicant stated that the differences between the CUF values reported for LGS Units 1 and 2 piping systems are caused by differences in piping configuration or other inputs to stress analyses. The applicant explained that the main reason for the difference in CUF values reported for the reactor recirculation piping is that different S_m (allowable stress) values were used in the original stress reports for the two units. The difference in S_m values between the two units leads to a difference in the elastic-plastic correction factor (K_e), which results in a higher alternating stress and higher CUF value for the LGS Unit 1 analysis. In addition, the applicant stated that the LGS Unit 2 fatigue analysis was revised to account for increased piping loads associated with a locked snubber condition on the recirculation piping line, which did not apply to LGS Unit 1. This condition also contributed to the difference in CUF values between the two units. The staff finds it reasonable that different S_m values and K_e factors in the two units and the operating experience in LGS Unit 2 reactor recirculation piping associated with the locked snubber would result in the large difference in CUF values between the two units.

The applicant also explained that the difference in nodal locations for the aforementioned systems between the two units and the staff's review of each of these nodal location differences is individually documented below.

The applicant stated that the difference in CUF values reported for the MSIV drain piping is caused by a difference in the piping support configuration downstream of the outboard isolation valves. On LGS Unit 1, the limiting nodes 41 and 261 are inside containment on the inboard of the MSIV drains header, and on LGS Unit 2, the limiting node 145 is outside containment immediately upstream of the HV-041-2F016 valve. In addition, the piping immediately downstream of the HV-041-1F016 valve on LGS Unit 1 includes a vertical restraint that is not present on LGS Unit 2. These differences between the two units resulted in a calculated CUF value of 0.0211 for nodes 41 and 261 on LGS Unit 1 and a computed CUF value of 0.0798 at node 145 on LGS Unit 2. The staff finds it reasonable that a different piping support configuration between the two units results in different applied forces, moments, and stresses, which equates to a different calculated CUF value.

For the CS system, the applicant stated that LGS Unit 1 had a locked snubber condition on one of the CS piping lines for a period of time before it was discovered and repaired; which resulted in a revision of the fatigue analysis. This condition resulted in an increased fatigue usage and a change in the limiting node in LGS Unit 1 when compared to LGS Unit 2. The staff finds it reasonable that the operating experience in LGS Unit 1 associated with the locked snubber would result in different calculated CUF values and limiting nodes between the two units.

For the MSIV drain and test piping (MSIV leakage control system), the applicant described the configuration for node 265 and node 517 for LGS Units 1 and 2, respectively. In addition, the applicant explained that node 265 was located on the 1-inch DBA-111 piping connected to 'D' Main steam line that was removed from the system by a modification. The applicant stated that the piping configuration for the MSIV leakage control system was substantially different between LGS Units 1 and 2 before and after the modifications, resulting in the different node locations and CUF values. The staff finds it reasonable that the design differences in piping configuration for the MSIV leakage control system and the modification to the LGS Unit 1 system would result in different calculated CUF values and limiting nodes between the two units.

For the RCIC steam supply piping, the applicant stated the stress analyses performed for power rerate in 1993 for LGS Unit 2, and in 1994 for LGS Unit 1, determined the different bounding locations and CUF values. The staff approved the LGS Unit 2 rerate by letter dated February 16, 1995, and the LGS Unit 1 rerate by letter dated January 24, 1996. The staff's SE determined that the applicant's submittal shows that the design of piping, components, and their supports is adequate to maintain the structural and pressure boundary integrity of the reactor coolant piping and supports in the power uprate conditions, and is, therefore, acceptable. The staff finds it reasonable that the difference in piping support configuration between the LGS Unit 1 and LGS Unit 2, RCIC steam supply system would result in different bounding nodal locations and calculated CUF values.

For the head vent piping, the applicant stated that the current CUF values for LGS Unit 1 (node 28 – 0.0891) and LGS Unit 2 (node 292 – 0.5044) are obtained from the ASME Code, Section III, Class 1 Stress Analysis Reports. For the safeguard piping fill systems, the applicant stated that the current CUF values for LGS Unit 1 (node 276 – 0.0047) and LGS Unit 2 (node 890 – 0.0021) are also obtained from the ASME Code, Section III, Class 1 Stress Analysis Reports. The applicant determined for both systems the causes of the difference in bounding values and locations are that the piping support configurations are different between the units. The staff finds this reasonable because a different piping support configuration between the two units would result in different applied forces, moments, and stresses, which equates to a different calculated CUF value.

The staff finds the applicant's response to RAI 4.3-7 acceptable because the applicant justified, as discussed above, the large differences in reported CUF values for the reactor recirculation piping and MSIV drains between LGS Units 1 and 2. In addition, the applicant justified, as described above, the differences in bounding nodal locations and CUF values for the CS piping, MSIV drains, MSIV drain and test, RCIC steam supply, head vent, and safeguard piping fill systems. The staff's concern described in RAI 4.3-7 is resolved.

LRA Section 4.3.3 states that to ensure that any other locations that may not be bounded by the NUREG/CR-6260 locations were evaluated, environmental fatigue calculations were performed for each RPV component location that has a reported CUF value in the stress report and for each ASME Code, Section III, Class 1 RCPB piping system in each unit. UFSAR Table 3A-27 identifies fatigue usage factors for components in the MSRV discharge lines in the wetwell air space. UFSAR Table 3.6-12 identifies cumulative usage factors for different locations of the reactor vessel drain piping. Table 3-7 of NEDO-33484, Revision 0, provides 40-year CUF values for the core differential-pressure and liquid control nozzle, closure bolts, and stabilizer bracket. The staff noted that LRA Table 4.3.3-1 and 4.3.3-2 did not identify any components in the MSRV discharge lines, reactor vessel drain piping, core differential-pressure and liquid control nozzle, closure bolts, and stabilizer bracket for the effects of reactor coolant environment. Therefore, it is not clear to the staff whether these component locations were considered when evaluating EAF.

By letter dated January 31, 2012, the staff issued RAI 4.3-8 requesting the applicant to justify why EAF does not need to be considered for the aforementioned components. In addition, the applicant was requested to identify and provide justifications for other RPV components and ASME Code, Section III, Class 1 RCPB piping systems that had reported CUF values but have not considered EAF.

In its response dated February 29, 2012, the applicant explained why an evaluation was or was not performed for the MSRV discharge lines, reactor vessel drain piping, core differential-pressure and liquid control nozzle, closure bolts, and stabilizer bracket. The staff's review of each explanation is documented below.

For the MSRV discharge lines, the applicant stated that these lines do not require evaluation for EAF because they are ASME Code, Section III, Class 3 components that are not within the RCPB and do not contact reactor coolant. Similarly, the applicant stated that the RPV closure bolts are located within the containment air space outboard of the RPV main flange seals and are not in contact with reactor coolant. The staff finds it acceptable that MSRV discharge lines and RPV closure bolts were not evaluated for the environmental fatigue because, consistent with GALL Report AMP X.M1, those components that are not part of the RCPB or not exposed to a reactor water environment and would not be included in the sample set of components that consider EAF.

For the reactor vessel drain piping, the applicant explained that this piping is included within the ASME Code, Class 1 stress report for the reactor water cleanup system and therefore, this piping was included within the environmental fatigue analysis for the reactor water cleanup system. The staff reviewed UFSAR Section 3.6.1.2.1.6 and confirmed that the reactor vessel drain piping is connected to the RWCU suction line in the drywell. Since the applicant considered the EAF for the reactor vessel drain piping as part of the reactor water cleanup system, the staff finds this acceptable.

For the core differential pressure and liquid control nozzle, the applicant stated that this component was analyzed for EAF; however, the EAF analysis determined that the alternating stress value is below the endurance limit for the material, resulting in a CUF value of 0.000 and CUF_{en} value of 0.000. The staff noted that if the alternating stress value is below the endurance limit for the material, there is no contribution of fatigue usage to the CUF value from transients that affect the component. Thus, the staff noted that the resulting CUF value and CUF_{en} value is zero and finds it reasonable that the applicant addressed EAF for the core differential pressure and liquid control nozzle.

For the RPV stabilizer bracket, the applicant stated that EAF was evaluated, as shown in LRA Table 4.3.3-1 for the "RPV Shell at Stabilizer Bracket." It was explained that the stabilizer bracket is welded to the outside surface of the RPV shell and the RPV stress report includes a fatigue analysis of the stabilizer bracket along with a segment of the RPV shell where the bracket is attached. The analysis provides a CUF value for a location on the inside surface of the RPV shell, which contacts reactor coolant, which was evaluated for EAF. Consistent with the recommendations of GALL Report AMP X.M1, the staff finds it acceptable that the applicant addressed EAF for the RPV stabilizer bracket location on the inside surface of the RPV shell since it is in contact with reactor coolant.

The applicant stated that components that are not in contact with reactor coolant are not required to be evaluated for EAF. In addition, piping systems with a dry steam internal environment were evaluated and shown to have a F_{en} value of 1.0 just to demonstrate that all ASME Code, Class 1, piping systems were evaluated. The staff finds it acceptable that the applicant applied a F_{en} value of 1.0 for components exposed to dry steam internal environment because EAF, as discussed in the GALL Report, is applicable to those components exposed to a reactor coolant environment. Additional information regarding this area of effects from a dry steam internal environment is documented in the staff's review of RAI 4.3-12.

The staff finds the applicant's response to RAI 4.3-8 acceptable because for those components identified in RAI 4.3-8, EAF was considered for all RCPB components exposed to a reactor coolant environment, consistent with the GALL Report and SRP-LR. The staff's review of the applicant's methodology for determining additional locations to manage EAF of the RPV and RCPB piping components exposed to reactor coolant is documented in its evaluation of RAI 4.3-6. The staff's concern described in RAI 4.3-8 is resolved.

LRA Table 4.3.3-2 shows that for the RCIC steam supply system, head vent system and HPCI steam supply system the F_{en} factor is 1.0 for both units. The LRA included footnote 8, which states that the F_{en} multiplier of 1.0 is used because the internal environment is dry steam. It was not clear to the staff why the LRA considered locations that are exposed to dry steam when addressing EAF and whether this was appropriate.

By letter dated January 31, 2012, the staff issued RAI 4.3-12 requesting the applicant to clarify whether there are other locations, which are not exposed to dry steam, within these systems that would be more appropriate when addressing the effects of reactor coolant environment.

In its response dated February 29, 2012, to RAI 4.3-12, the applicant stated that since the RCIC steam supply system, head vent system and HPCI steam supply system include only a dry steam environment, the F_{en} value of 1.0 was applied, which indicates that there is no increase in fatigue usage caused by environmental effects. The applicant confirmed that there are no other locations within the ASME Code, Section III, Class 1 boundary for these systems that would be more appropriate to evaluate for environmental fatigue effects. The staff noted that UFSAR Section 3.6.1.2.1.7, 3.6.1.2.1.8, and 3.6.1.2.1.10 indicate that HPCI steam supply line, RCIC steam supply line, and head vent, respectively, are connected from the main steam line, which confirms that these piping systems are exposed to dry steam only.

The staff finds the applicant's response to RAI 4.3-12 acceptable because the staff confirmed that the piping systems in HPCI steam supply line, RCIC steam supply line, and head vent are exposed to dry steam only, and thus, it is acceptable to use a F_{en} value of 1.0 for these systems. In addition, the staff finds that the applicant performed a thorough evaluation of its plant-specific configuration by including these piping systems exposed to dry steam to ensure that no ASME Code, Class 1, piping systems were overlooked when considering EAF. The staff's concern described in RAI 4.3-12 is resolved.

LRA Table 4.3.3-2 indicates that the 40-year CUF value for the feedwater piping is 0.8011 at node 100 for both units. It was not apparent to the staff whether node 100 for LGS Unit 1 in LRA Table 4.3.3-2 refers to the same nodal location described in UFSAR Table 3.6-8 with a CUF value of 0.3651 or the LRA denotes that node 100 for the feedwater piping of LGS Unit 2 bounds LGS Unit 1.

By letter dated January 31, 2012, the staff issued RAI 4.3-11 requesting the applicant to clarify and justify the entry of the CUF value for the LGS Unit 1 feedwater piping in LRA Table 4.3.3-2. In addition, the applicant was requested to identify any other components or locations in LRA Tables 4.3.3-1 and 4.3.3-2 in which a CUF value for one unit was used to bound the same component/location in the other unit.

In its response dated February 29, 2012, to RAI 4.3-11 the applicant stated that the locations and CUF values shown in LRA Table 4.3.2-2 for LGS Units 1 and 2, feedwater piping are applicable to both units. Stress analysis documentation shows that the locations and CUF values for the feedwater piping system are the same between the units. The applicant also stated that the RHR supply and return, recirculation drain, main steam (line c), instrumentation, and HPCI steam supply in LRA Table 4.3.3-2 used the same CUF value for the same component location on both units because the values from the current stress analyses are identical for both units.

The applicant further explained that the CS nozzle (safe end) and CS nozzle (forging) are the only cases where the bounding location and CUF values for LGS Unit 1 are applied for Unit 2. The applicant stated that LGS Unit 1 bounds LGS Unit 2 because of a historical locked-snubber condition on the LGS Unit 1 CS piping, which resulted in increased applied loads from the piping system to the safe end and nozzle, which in turn would increase the CUF value. LRA Table 4.3.3-1 was revised to include a note to indicate that the bounding LGS Unit 1 ASME CUF values for the CS nozzle (safe end) and CS nozzle (forging) are used for LGS, Unit 2. The staff finds this reasonable because a locked snubber condition would result in different applied forces, moments, and stresses, which resulted in a different calculated CUF value.

The staff finds the applicant's response to RAI 4.3-11 acceptable because the applicant clarified that the calculated CUF values in the stress analyses between LGS Units 1 and 2 are identical in the feedwater piping, RHR supply and return, recirculation drain, main steam (line c), instrumentation, and HPCI steam supply is caused by identical piping configurations. In addition, the staff finds the applicant's explanation that the LGS Unit 1 CS nozzle safe end and forging bound the LGS Unit 2 configuration based on the locked snubber operating experience in LGS Unit 1 to be reasonable. The staff's concern described in RAI 4.3-11 is resolved.

LRA Section 4.3.3 states that to ensure that other locations that may not be bounded by the NUREG/CR-6260 were evaluated, environmental fatigue calculations were performed for each RPV component location that has a reported CUF value in the stress report in each unit. In addition, each ASME Code, Section III, Class 1 RCPB piping system from each unit that has a reported CUF value in the stress report was evaluated. These calculations were performed for the limiting location for each material within the component or system that contacts reactor coolant. The applicant's criteria for selecting locations to evaluate EAF were not clear; therefore, the staff was not able to determine whether other locations not provided in the LRA should have been considered. It was also not clear whether the applicant considered ASME Code, Section III, Class 1 valves when addressing EAF. By letter dated January 31, 2012, the staff issued RAI 4.3-6 requesting the applicant to (Part 1) justify its methodology for selecting locations to evaluate EAF, (Part 2) discuss whether the variation of certain parameters (thermal transient loadings, water chemistry conditions, etc.), were considered, and (Part 3) clarify whether Class 1 valves were also considered in this methodology.

In its response dated February 29, 2012, to Part 3, the applicant stated that ASME Code, Section III, Class 1 valve design reports were reviewed and representative valves were evaluated for environmental fatigue effects, based on the formulation in NUREG/CR-6909. The applicant explained that ASME Code design requirements specified in NB-3500 for ASME Code, Section III, Class 1 valves are different than the requirements for the ASME Code, Section III, Class 1 piping systems. Specifically, Subsection NB-3552 allows certain cycles to be excluded from valve cyclic loading analysis. However, the applicant stated that its ASME Code, Section III, Class 1 valve fatigue analyses did not always exclude these cycles and, therefore, have conservative fatigue usage results in many cases. The environmental fatigue analyses performed for the ASME Code, Section III, Class 1 valves removed conservatism from the original analyses by removing events that meet the exclusion criteria in Subsection NB-3552. Consistent with Subsection NB-3552, the staff finds it reasonable that the applicant reduced the calculated CUF values in the original analyses by removing events that meet the ASME Code exclusion criteria. The applicant stated that F_{en} values were developed based upon temperatures associated with the evaluated transients and environmental conditions appropriate for the system; the resulting CUF_{en} values were determined to be less than the design limit of 1.0. As part of the applicant's response to RAI 4.3-6, a table containing the results of the EAF evaluations for ASME Code, Section III, Class 1 valves was provided; the staff noted that all CUF_{en} values were less than 1.0.

The staff noted that some valves are represented by an analyzed valve that is bounding. In these instances, the analyzed valves and the unanalyzed valves were located in the same system and have the same valve size, material and pressure classification, except for the 12-inch stainless steel RHR shutdown cooling (RHR-SDC), RHR-LPCI, and CS valves rated at 900 lbs. Except for these 12-inch valves, the staff finds it reasonable that the applicant used a bounding analysis because the valves being represented have the same characteristics (e.g., size, material and pressure classification) and experience the same transients as the analyzed valve. For the 12-inch stainless steel RHR-SDC, RHR-LPCI, and CS injection valves rated at 900 lbs the applicant stated that the RHR-SDC system valves are exposed to transients associated with shutdown cooling operations that are not experienced by the RHR-LPCI and CS injection valves. In addition, the applicant also stated that the RHR-LPCI and CS injection valves are only exposed to transients that are also experienced by the RHR shutdown cooling return valves. Based on this description, it was not clear to the staff what transients were associated with the RHR-SDC, RHR-LPCI, and CS valves; therefore, the staff was not able to determine whether it was reasonable that these valves were evaluated collectively. By letter dated April 17, 2012, the staff issued followup RAI 4.3-6.2 requesting the applicant to clarify which transients are experienced by these 12-inch stainless steel RHR-SDC, RHR-LPCI, and CS valves.

In its response dated May 4, 2012, the applicant stated that the RHR-SDC valves and RHR-LPCI and CS injection valves are analyzed for the same numbers and types of design transients as those listed in LRA Tables 4.3.1-1 and 4.3.1-2 (except for those that only apply to the RPV), and the thermal profile of the shutdown transient is different for the SDC valves than for the other valves. The applicant stated that the thermal profile for the shutdown transient applicable to the RHR-LPCI and CS injection valves is a cooldown from reactor temperature to ambient at a rate not exceeding 100 °F/hr and there is no flow through these valves during a shutdown transient, so they slowly cool down with RPV temperature. However, the thermal profile for the shutdown transient applicable to the RHR-SDC valves is different because there is flow through the RHR-SDC valves during a shutdown transient, which includes a step change from 553 °F to 100 °F associated with SDC operation when cold water in the piping is assumed to flow through the hot valve. The fatigue usage associated with this step change accounts for approximately two thirds of the total fatigue usage in the analysis. Based on the applicant's clarification, the staff finds it reasonable that the environmental fatigue analysis of the RHR-SDC valve bounds the RHR-LPCI and CS injection valves because the transients experienced by the RHR-SDC are more severe than the other valves and, thus, the RHR-SDC valve incurs more fatigue usage.

The staff finds the applicant's response to followup RAI 4.3-6.2 acceptable because the applicant clarified the transients associated with the RHR SDC valve are more severe than those experienced by RHR LPCI and CS injection valves; such that the EAF analysis for the RHR SDC valves is bounding for these components. The staff's concern identified in followup RAI 4.3-6.2 is resolved.

In addition, the staff noted that LRA Sections 4.3.3 and A.4.3.3 were not updated to include the results and description of the evaluation of EAF for ASME Code Class 1 valves. Therefore, it was not clear to staff whether these EAF evaluations are also dispositioned in accordance with 10 CFR 54.21(c)(1)(iii) and will be managed by the Fatigue Monitoring program. By letter dated April 17, 2012, the staff issued followup RAI 4.3-6.1 requesting the applicant to confirm the disposition of the EAF evaluations for the ASME Code Class 1 valves or make appropriate revisions to the LRA.
In its response dated May 4, 2012, the applicant stated the environmental fatigue analyses prepared for ASME Code Class 1 valves will be managed by the Fatigue Monitoring program in the same manner as all other Class 1 environmental fatigue analyses discussed in LRA Sections 4.3.3 and A.4.3.3. Specifically, the program will ensure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting fatigue analysis, including these Class 1 valve environmental fatigue analyses. The applicant confirmed that the Class 1 valve environmental fatigue analyses are included within the disposition of 10 CFR 54.21(c)(1)(iii), provided in LRA Sections 4.3.3 and A.4.3.3.

The staff finds the applicant's response to followup RAI 4.3-6.1 acceptable because the applicant confirmed that the disposition of 10 CFR 54.21(c)(1)(iii) identified in LRA Sections 4.3.3 and A.4.3.3 is applicable to the environmental fatigue analyses for ASME Class 1 valves, such that the Fatigue Monitoring program will ensure that the environmentally assisted fatigue of these valves will be managed through the period of extended operation. The staff's review of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff's concern identified in followup RAI 4.3-6.1 is resolved.

In response to the staff's concern in RAI 4.3-6, Part 1, regarding its methodology for selecting the locations to evaluate EAF in LRA Tables 4.3.3-1 and 4.3.3-2, the applicant provided a detailed explanation of its methodology, which the staff evaluates below in the following categories: NUREG/CR-6260 RPV component locations, NUREG/CR-6260 RCPB piping locations, other RPV component locations, and other RCPB locations.

The applicant stated that the RPV component locations identified in NUREG/CR-6260 for a newer-vintage BWR plant design include the RPV shell and lower head (including CRD housing, stub tube, and vessel shell adjacent to stabilizer bracket), feedwater nozzle and safe end, recirculation inlet and outlet nozzle and safe end, CS nozzle and safe end, and LPCI nozzle and safe end. In addition, the EAF analyses for these components were performed using the formulation in NUREG/CR-6909, as described in LRA Section 4.3.3. Consistent with SRP-LR Section 4.3.2.1.3, the applicant considered the sample set of RPV component locations identified in NUREG/CR-6260 for a new vintage GE plant; therefore, the staff finds it acceptable. In addition, the use of NUREG/CR-6909 to determine the F_{en} factor is consistent with SRP-LR Section 4.3.2.1.3; therefore, the staff finds it acceptable.

The applicant stated that the RCPB piping locations identified in NUREG/CR-6260 for its plant design include the RHR return piping, LPCI piping, feedwater piping, CS piping, and reactor recirculation piping. Each location was analyzed by the applicant for reactor coolant environmental effects using F_{en} factor determined for the location. The staff noted that these analyses were performed using the formulation in NUREG/CR-6909, as described in LRA Section 4.3.3. Consistent with SRP-LR Section 4.3.2.1.3, the applicant considered the sample set of RCPB piping locations identified in NUREG/CR-6260 for a new vintage GE plant; therefore, the staff finds it acceptable. In addition, the use of NUREG/CR-6909 to determine the F_{en} factor is consistent with SRP-LR Section 4.3.2.1.3; therefore, the staff finds it acceptable.

The applicant stated that additional environmental fatigue analyses were performed to determine if any other RPV component locations beyond those identified in NUREG/CR-6260 are limiting. For the RPV, the remaining RPV locations (i.e., locations not identified in NUREG/CR-6260) that have a reported CUF value in the design stress report were evaluated. The applicant stated that this does not include locations identified in the stress report as having met the exemption requirements of ASME Code Section III. The staff finds this acceptable because the applicant demonstrated as part of its CLB that fatigue, as defined by the ASME Code, is not applicable to these exempted locations. The applicant stated that for each RPV component with a reported CUF value, a further review was performed to identify each material type within the component in contact with reactor coolant (not including cladding), and for each material type, the location with the highest CUF value was evaluated for environmental fatigue. The staff finds it conservative that the applicant considered each material type for component locations with a reported CUF value in the design stress report because no component locations were eliminated, without justification, from consideration for selecting additional EAF locations. The staff finds it reasonable that the applicant disregarded the cladding because the cladding thickness would not typically be considered when satisfying cyclic stress requirements, consistent with ASME Code, Section III, Subsection NB-3122, since the base metal is providing the pressure-boundary function.

The applicant stated that it reviewed the stress report for each ASME Code Class 1 RCPB piping system in order to determine other RCPB piping locations to consider. The applicant explained that the stress reports for systems that only have dry steam inside were included to demonstrate that no ASME Code Class 1 piping system was overlooked. The staff finds that the applicant performed a thorough evaluation of its plant-specific piping configuration by including these piping systems exposed only to dry steam to ensure that no ASME Code Class 1 piping systems were overlooked when considering EAF. The applicant stated that the location within each ASME Code Class 1 stress report with the highest CUF value was selected for an environmental fatigue evaluation, even though, in some cases, a single stress report includes coupled piping from more than one system. In addition, the applicant stated that its approach in selecting and evaluating the highest CUF is valid because the entire system, including the coupled piping, would be analyzed for the same thermal and pressure transients. The staff finds the applicant's justification acceptable because, during the design of the plant, all locations within a particular ASME Code Class 1 piping system were analyzed on a consistent basis (e.g., transient severity and applied loadings), which allows for an equal comparison of CUF values within that system and selection of a critical location based on the highest CUF value. The applicant further explained that, for cases where multiple materials were included within the stress report, calculations were performed for the limiting location for each wetted material type. The staff finds the consideration of all the different wetted material types appropriate because the effects of EAF are different between carbon steel, low-alloy steel, stainless steel, and nickel alloys.

In response to the staff's concerns in RAI 4.3-6, Part 2, provided by letter dated February 29, 2012, related to the analyzed transients, material, and effects of connected piping on a component location, the applicant stated that each ASME Code Class 1 stress report evaluates the components within its scope for the same transients plus the applied loadings from interfacing systems. As described previously for ASME Code Class 1 piping systems, the staff finds this rationale acceptable, which is also applicable to RPV component locations. The applicant stated that dissolved oxygen concentrations were determined for each region within the RPV and for each ASME Code Class 1 piping system based upon reactor vessel water chemistry data for each of three operating regimes, i.e., normal water chemistry (NWC), hydrogen water chemistry (HWC), and HWC with noble metal chemical addition (NMCA). Since the F_{en} value is dependent on dissolved oxygen levels, the staff finds it appropriate that the applicant considered the different operating regimes for water chemistry conditions at its plant based on the reactor vessel water chemistry data for the applicable RPV locations and ASME Class 1 piping when accounting for EAF.

The staff noted that the applicant's methodology for selecting additional locations to manage EAF considered its plant-specific configuration. Specifically, the applicant considered the following: the specific transients that affect the RPV component and ASME Code Class 1 piping system; each material type, if applicable, for the RPV component and ASME Code Class 1 piping system; applicable water chemistry conditions (i.e., dissolved oxygen level) at the RPV component and ASME Class 1 piping location; the different water chemistry operating regimes since initial plant operation (i.e., NWC, HWC ,and HWC with NMCA) and the attached piping to the component or system, as considered in the original design stress report.

The staff finds the applicant's response to all parts of RAI 4.3-6 acceptable because, consistent with recommendations in the GALL Report and the SRP-LR, the applicant considered the effects of reactor coolant environment on metal life for the sample locations identified in NUREG/CR-6260 and additional locations beyond NUREG/CR-6260 that are based on the applicant's plant-specific configuration. In addition, the applicant demonstrated that its review considered all RCPB component location in contact with reactor coolant when identifying additional locations to consider EAF, which is comprehensive. The staff's concerns described in RAI 4.3-6 are resolved.

The staff's review of the applicant's Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in fatigue evaluations. In addition, the program requires comparison of the actual event parameters to the applicable design transient definitions to assure the actual transients are bounded by the design transients. If a transient approaches an action limit, which the applicant has set to 80 percent of the cycle limit, corrective actions are initiated for repair, replacement, or reanalysis of the component, in accordance with the Fatigue Monitoring program. The staff determined that these characteristics of the applicant's Fatigue Monitoring program are consistent with GALL Report AMP X.M1. The staff noted that the applicant's method for managing these ASME Code Class 1 fatigue analyses is conservative, because corrective actions are initiated when one transient type approaches 80 percent of the cycle limit, when typically an ASME Code Class 1 fatigue analysis includes more than one transient type.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed by the Fatigue Monitoring program for the period of extended operation. Additionally, the applicant's demonstration meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant is crediting its Fatigue Monitoring program, which the staff has determined is consistent with GALL Report AMP X.M1, to manage EAF by monitoring transient occurrences to ensure that the assumptions in the EAF analyses remain valid during the period of extended operation; otherwise, the applicant will take corrective actions in accordance with its program.

4.3.3.3 UFSAR Supplement

LRA Section A.4.3.3 provides the UFSAR supplement summarizing evaluations of the effects of the reactor coolant environment on fatigue life of piping and components. The staff reviewed LRA Section A.4.3.3, consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluations for the effects of the reactor coolant environment on fatigue life of piping and components.
Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the effects of reactor coolant environment on component fatigue life, as required by 10 CFR 54.21(d).

4.3.3.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of reactor coolant environment on component fatigue life will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the evaluations, as required by 10 CFR 54.21(d).

4.3.4 Reactor Vessel Internals Fatigue Analyses

4.3.4.1 Summary of Technical Information in the Application

LRA Section 4.3.4 describes the applicant's metal fatigue TLAA for RVIs. The LRA states that the reactor internals were designed and procured before the issuance of ASME Code Section III, Subsection NG. However, an earlier draft of the ASME Code was used as a guide in the design of the reactor internals, and subsequent to the issuance of Subsection NG, comparisons were made to ensure that the pre-NG design meets the equivalent level of safety as presented by Subsection NG. The applicant determined that these fatigue analyses have been identified as TLAAs that require evaluation for the period of extended operation.

The applicant dispositioned the fatigue TLAA for RVIs in accordance with 10 CFR 54.21(c)(1)(i) to demonstrate that the analyses remain valid during the period of extended operation.

4.3.4.2 Staff Evaluation

The staff reviewed the applicant's metal fatigue TLAAs for RVIs and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.1, which states that the operating transient experience and a list of the assumed transients used in the existing CUF calculations for the current operating term are reviewed to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

LRA Section 4.3.4 states that the fatigue analyses performed for the RVIs are based upon the same set of design transients as those used in the fatigue analyses for the RPV. Furthermore, as previously shown on Tables 4.3.1-1 and 4.3.1-2, transient cycle projections were prepared that demonstrate these design transient cycle limits will not be exceeded in 60 years; therefore, these analyses remain valid through the period of extended operation. However, since this TLAA relies on 60-year projections that are dependent on the Fatigue Monitoring program (i.e., managing the number of cycles), the staff was not clear on implications for cases where the Fatigue Monitoring program may determine that a transient cycle count reaches a cycle limit. By letter dated November 18, 2011, the staff issued RAI B.3.1-1, requesting the applicant to provide clarification.

In its response dated December 7, 2011, the applicant confirmed that the TLAA for RVIs is within scope of the Fatigue Monitoring program and based on the same set of design transients that this program monitors and trends. As such, the applicant confirmed that its procedure requires its engineers to initiate corrective action to demonstrate the design limit will not be exceeded before or during the period of extended operation; otherwise, further action for repair or replacement of the component, or other methods approved by the staff will be taken. As described in SER Section 3.0.3.2.20 the staff determined that the applicant ensures that the results from its 60-year projections, which are used to disposition the TLAA for RVIs in accordance with 10 CFR 54.21(c)(1)(i), will remain valid during the period of extended operation, otherwise corrective actions will be taken.

In the applicant's submittal dated March 25, 2010, "Request for License Amendment Regarding Measurement Uncertainty Recapture Power Uprate," a non-proprietary report NEDO–33484, Revision 0, "Safety Analysis Report for Limerick Generating Station Units 1 & 2 Thermal Power Optimization" was provided. Section 3.3.2 of this report states that the loads considered in the evaluation of the RVIs include the safety relief valve (SRV) transients. LRA Sections 4.3.4 and A.4.3.4 state that the fatigue analyses performed for the RVIs are based upon the same set of design transients as those used in the fatigue analyses for the RPV; however, the staff noted that transients related to SRV are not included in LRA Tables 4.3.1-1 and 4.3.1-2.

It was not clear to the staff whether the transients related to the SRVs were used in the fatigue analyses for the RVIs. In addition, the LRA does not provide CUF values for the RVIs; thus, the staff cannot determine whether the CUF for any location will exceed the allowable limit during the period of extended operation. By letter dated January 31, 2012, the staff issued RAI 4.3-10 requesting the applicant to clarify the discrepancy between the LRA and the non-proprietary report and identify the RVIs with CUF values.

In its response dated February 29, 2012, the applicant stated that SRV transients were considered in the fatigue evaluation of the RVIs, as stated in NEDO–33484, Revision 0. As indicated in UFSAR Section 3.9.1.1.9, at least 7,700 SRV cycles are considered to account for the pool dynamic loads for the RPV and RVIs and that these cycles are based on 1,100 actuations of all MSRVs times seven stress cycles per actuation. The staff noted that these pool dynamic loads are associated with the suppression pool and are defined in UFSAR Section 3.9.3.3.1. The applicant stated that details regarding 60-year projections of the MSRV cycles, the addition of MSRV actuation cycles to the Fatigue Monitoring program, and related changes to the LRA are discussed in its response to RAI 4.6.8-1. The staff's review of the applicant's response to RAI 4.6.8-1 is documented in SER Section 4.6.8. The staff confirmed that the applicant amended the LRA to include Transient No. 20, MSRV Actuations, into the Fatigue Monitoring program and finds this acceptable because the applicant will be able to manage fatigue by ensuring that the assumptions in its TLAA for RVIs remain valid during the period of extended operation.

As part of the applicant's February 29, 2012, response, LRA Table 3.1.2-3 was revised to add aging management review (AMR) items for the core shroud, core plate, LPCI coupling, CS lines and spargers, orificed fuel support, and jet pump, all to be managed for cumulative fatigue damage. The staff finds the applicant's revision acceptable because the LRA was amended to include those systems, structures and components subject to an AMR in accordance with 10 CFR 54.21(a)(1).

The applicant also stated that in order to ensure that the transient cycle projections used in evaluating the RVIs fatigue TLAAs remain bounding through the period of extended operation, the disposition for these TLAAs in LRA Sections 4.3.4 and Section A.4.3.4 is revised from 10 CFR 54.21(c)(1)(i) to 10 CFR 54.21(c)(1)(iii), crediting the Fatigue Monitoring program with managing fatigue through the period of extended operation.

The staff's review of the applicant's Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting ASME Code, Class 1 fatigue analysis. In addition, the program requires comparison of the actual event parameters to the applicable design transient definitions to assure the actual transients are bounded by the applicable design transients. If a transient approaches an action limit, which the applicant has set to 80 percent of the cycle limit, corrective actions are initiated for repair, replacement, or reanalysis of the component, in accordance with its Fatigue Monitoring program. The staff determined that these characteristics of the applicant's Fatigue Monitoring program are consistent with GALL Report AMP X.M1.

The staff also reviewed the CUF values provided by the applicant in response to RAI 4.3-10 and confirmed that the design CUF values for the components associated with the RVIs are less than the design limit of 1.0. The applicant also indicated that the steam dryer, steam dryer support brackets, and control rod guide tube are "exempt." The applicant did not explain why these three components are exempt from a fatigue analysis. By letter dated April 17, 2012, the staff issued followup RAI 4.3-10.1 requesting the applicant clarify why these three components are exempt and identify the provisions in the ASME Code, Section III, that allowed the exemption of the required fatigue analysis for these components.

In its response dated May 4, 2012, the applicant stated that the steam dryer support brackets were evaluated in the RPV stress report and the report stated that "exemption from fatigue analysis per N-415.1 (of the design Code) is satisfied." The design code of the brackets was the 1968 Edition of the ASME Code Section III with Addenda through Summer 1969. The response also indicated that the control rod guide tube was exempted from fatigue analysis per Paragraph NG-3222.4(d) of the ASME Code, Section III.

The staff noted that the fatigue waiver provisions in N-415.1 indicated that fatigue analyses were not required when all of four specific conditions were met. In particular, the staff noted that Condition (a) of N-415.1 required that the specified numbers of times (including startup and shutdown) that the pressure will be cycled from atmospheric pressure to the operating pressure and back to atmospheric pressure shall not exceed certain requirements. Therefore, the staff noted that such cycling indicates that Condition (a) of N-415.1 is a time-dependent parameter. The response to RAI 4.3-10.1 did not provide a justification of why the fatigue waivers were not identified as TLAAs in the LRA. By letter dated June 12, 2012, the staff issued followup RAI 4.3-10.2 requesting the applicant justify whether or not the fatigue waivers for the control rod guide tube and the steam dryer support brackets should be identified as TLAAs for the LRA and confirm that all fatigue waiver provisions in the ASME Code, Section III, have been identified as TLAAs, as applicable.

In its response dated June 19, 2012, the applicant stated that fatigue exemptions (or fatigue waivers) are TLAAs because they meet all six TLAA criteria defined in 10 CFR 54.3. The applicant stated that Criterion 3 is met because the time-limited assumptions are based upon an evaluation of the thermal and pressure transients defined for 40 years in the design specifications for ASME Code Section III Class 1 and RVI components. The applicant also revised LRA Sections 4.3.1 and 4.3.4 to clarify that all fatigue exemptions have been identified as TLAAs and are managed by the Fatigue Monitoring program. The applicant also stated that UFSAR supplement Sections A.4.3.1 and A.4.3.4 and Appendix B, Section B.3.1.1 were revised with conforming changes.

The staff confirmed that the fatigue exemption provisions, for Class 1 components, in N-415.1 of the 1968 ASME Code Section III and Paragraph NB-3222.4(d) of the 1971 and later ASME Code Section III depended on the assumption of the number of occurrence of transients (such as startup and shutdown) that is a time-dependent parameter. The staff also confirmed that the fatigue exemption provisions, for RVI components, in Paragraph NG-3222.4(d) of the ASME Code Section III depended on a similar assumption. The staff concluded that the applicant appropriately identified the fatigue exemption as a TLAA in accordance with 10 CFR 54.21(c)(1).

The staff finds the applicant's responses to RAI 4.3-10, followup RAIs 4.3-10.1 and 4.3-10.2 acceptable because the applicant (1) clarified the discrepancy between the LRA and the non-proprietary report; (2) identified the RVI components with CUF values and those that were exempted from fatigue analyses; and (3) identified and dispositioned fatigue exemptions in accordance with 10CFR 54.21 (c)(1). The staff concerns identified in RAI 4.3-10, followup RAIs 4.3-10.1 and 4.3-10.2 are resolved. The staff's review of the revised LRA Section 4.3.4 is documented below.

The staff noted that the applicant credits its Fatigue Monitoring program to disposition the fatigue analyses and fatigue exemptions TLAAs for RVI components. The staff's review of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the analyses. In addition, the program requires comparison of the actual event parameters to the applicable design transient definitions to assure the actual transients are bounded by the applicable design transients. If a transient approaches an action limit, which the applicant has set to 80 percent of the cycle limit, corrective actions are triggered for repair, replacement, or reanalysis of the component, in accordance with its Fatigue Monitoring program. The staff determined that these characteristics of the Fatigue Monitoring program are consistent with GALL Report AMP X.M1.

Based on its review, the staff finds the applicant has demonstrated in accordance with 10 CFR 54.21(c)(1)(iii) that the effects of metal fatigue on the intended functions of the RVIs components analyzed in accordance with ASME Code Section III, Subsection NG requirements will be adequately managed by the Fatigue Monitoring program for the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP–LR Section 4.3.2.1.1.3 because the applicant is crediting its Fatigue Monitoring program, which the staff has determined is consistent with GALL Report AMP X.M1, to manage metal fatigue by monitoring transient occurrences to assure that the assumptions in the fatigue analyses and fatigue exemptions remain valid during the period of extended operation; otherwise the applicant will take corrective actions in accordance with its program.

4.3.4.3 UFSAR Supplement

LRA Section A.4.3.4, as amended by letters dated February 29, 2012 and June 19, 2012, provides the UFSAR supplement summarizing the metal fatigue TLAAs for RVIs. The staff reviewed LRA Section A.4.3.4, consistent with the review procedure in SRP-LR Section 4.3.3.2, which states that the reviewer verifies that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAAs.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the RVI metal fatigue and fatigue exemption TLAAs, as required by 10 CFR 54.21(d).

4.3.4.4 Conclusion

On the basis of its review the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that effects of metal fatigue for RVIs will be adequately managed by the Fatigue Monitoring program for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.3.5 High-Energy Line Break Analyses Based Upon Fatigue

4.3.5.1 Summary of Technical Information in the Application

LRA Section 4.3.5 describes the applicant's TLAA for HELB analyses based upon fatigue. The LRA states that HELB analyses used the CUF values from the ASME Code, Class 1 fatigue analyses as input in determining intermediate break locations. Furthermore, locations with a CUF value less than 0.1 did not always require a break to be postulated. Therefore, since the HELB analyses are based on the CUF values in ASME Code Class 1 fatigue analyses, they have also been identified as TLAAs.

The applicant dispositioned the TLAA for the HELB analyses based upon fatigue in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid during the period of extended operation.

4.3.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for HELB analyses based upon fatigue and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedure in SRP-LR Section 4.3.3.1.1.1, which states that the operating transient experience and a list of the assumed transients used in the existing CUF calculations for the current operating term are reviewed to ensure that the number of assumed transients would not be exceeded during the period of extended operation.

The staff noted that UFSAR Section 3.6 contains information associated with the applicant's HELB analyses, which rely on the CUF that was calculated for the ASME Code, Section III, Class 1 requirements. LRA Section 4.3.5 states that transient cycle projections were performed and determined that the 40-year transient cycle limits will not be exceeded in 60 years of operation. The staff's evaluation of the applicant's cycle projection is documented in SER Section 4.3.1. LRA Section 4.3.5 states that since the ASME Code, Class 1 piping fatigue analyses were demonstrated to remain valid for the period of extended operation, the HELB break determinations based upon these fatigue analyses will also remain valid for the period of extended operation.

However, since this TLAA relies on 60-year projections that are dependent on the Fatigue Monitoring program (i.e., managing the number of cycles), the staff was not clear on implications for cases where the Fatigue Monitoring program may determine that a transient cycle count reaches a cycle limit. By letter dated November 18, 2011, the staff issued RAI B.3.1-1, requesting the applicant to provide clarification.

In its response dated December 7, 2011, the applicant confirmed that the TLAA for HELB analyses is within scope of the Fatigue Monitoring program and is based on the same set of design transients that the program monitors and trends. As such, the applicant confirmed that its procedure requires its engineers to initiate corrective action to demonstrate the design limit will not be exceeded before or during the period of extended operation; otherwise, further action for repair of the component; replacement of the component, or other methods approved by the staff will be taken. The staff determined in SER Section 3.0.3.2.20, that the applicant continually ensures that the results from its 60-year projections used to disposition the HELB

TLAA in accordance with 10 CFR 54.21(c)(1)(i), will remain valid during the period of extended operation; otherwise, corrective actions will be taken.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAA for HELB analyses based upon fatigue, remain valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.3.2.1.2.1 because the projected number of transient cycles over the period of extended operation is not expected to exceed the design cycle limit used in the HELB analyses. However, in any event, the applicant confirmed that these analyses are within the scope of the Fatigue Monitoring program, which will ensure that the results from its projections used to disposition this TLAA will remain valid during the period of extended operation, otherwise corrective actions will be taken.

4.3.5.3 UFSAR Supplement

LRA Section A.4.3.5 provides the UFSAR supplement summarizing the TLAA for HELB analyses based upon fatigue. The staff reviewed LRA Section A.4.3.5, consistent with the review procedures in SRP-LR Section 4.3.3.2, which states that the reviewer verifies that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of HELB analyses based upon fatigue, as required by 10 CFR 54.21(d).

4.3.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the HELB analyses based upon fatigue remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.4 Environmental Qualification of Electric Equipment

4.4.1 Summary of Technical Information in the Application

LRA Section 4.4 describes the applicant's TLAA for the evaluation of environmentally qualified electrical equipment for the period of extended operation. The applicant stated the EQ program manages component thermal, radiation, and cyclical aging, as applicable, through the use of aging evaluations based on 10 CFR 50.49(f) qualification methods.

LRA Section 4.4 discusses the component reanalysis attributes, including analytical models, data collection and reduction methods, underlying assumptions, acceptance criteria, and corrective actions.

The applicant dispositioned the EQ of Electric Components TLAA in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

4.4.2 Staff Evaluation

The staff reviewed LRA Section 4.4, "Environmental Qualification of Electric Components," TLAA to verify, pursuant to 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions will be adequately managed for the period of extended operation.

The staff reviewed the applicant's TLAA and the corresponding disposition, consistent with the review procedure in SRP-LR Section 4.4.3.1.3, which states that the reviewer verifies that the applicant has stated that its environmental qualification program contains the same program elements that the staff evaluated and relied upon in approving the corresponding generic program in the GALL Report.

The environmental qualification requirements established by 10 CFR Part 50, Appendix A, Criterion 4, and 10 CFR 50.49 specifically require each applicant to establish a program to qualify electrical equipment so that such equipment, in its end of life condition, will meet its performance specifications during and following design basis accidents. The EQ of electrical components is a TLAA for purposes of license renewal. The TLAA of the EQ of electrical components includes all long-lived, passive, and active electrical and instrumentation and controls (I&C) components that are important to safety and are located in a harsh environment. The harsh environments of the plant are those areas subject to environmental effects by a LOCA, a HELB, or post-LOCA environment. EQ equipment comprises safety-related and nonsafety-related equipment, the failure of which could prevent satisfactory accomplishment of any safety-related function, and necessary post-accident monitoring equipment.
The staff reviewed LRA Sections 4.4 and B.3.1.2, plant basis documents, additional information provided to the staff, and interviewed plant personnel to verify whether the applicant provided adequate information to meet the requirement of 10 CFR 54.21(c)(1). For electrical equipment, the applicant uses 10 CFR 54.21(c)(1)(iii) in its TLAA evaluation to demonstrate that the aging effects of EQ equipment will be adequately managed during the period of extended operation. Based on the GALL Report, plant EQ programs that implement the requirements of 10 CFR 50.49 are considered acceptable AMPs under license renewal 10 CFR 54.21(c)(1)(iii). GALL Report AMP X.E1, "Environmental Qualification (EQ) of Electric Components," provides a means to meet the requirements of 10 CFR 54.21(c)(1)(iii). The staff reviewed the applicant's EQ program to determine whether it will assure that the electrical and I&C components covered under this program will continue to perform their intended functions, consistent with the CLB, for the period of extended operation.

The staff's evaluation of the component qualifications focused on how the EQ program manages the aging effects to meet the requirements in 10 CFR 50.49. The staff conducted an audit of the information provided in LRA Sections 4.4 and B.3.1.2 and the program basis documents. On the basis of its audit, and as described in SER Section 3.0.3.1.25, the staff found that the Environmental Qualification of Electric Components program, which the applicant claimed to be consistent with GALL Report AMP X.E1, "Environment Qualification (EQ) of Electric Components," is consistent with the GALL Report. Therefore, the staff concludes that the applicant's Environmental Qualification of Electric Components TLAA is implemented per the requirements of 10 CFR 54.21(c)(1)(iii).

The staff finds the applicant has demonstrated in accordance with 10 CFR 54.21(c)(1)(iii) that the effects of aging on the intended functions of the Environmental Qualification of Electric Components TLAA will be adequately managed for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.4.2.1 because the Environmental Qualification of Electric Components program is capable of programmatically managing the qualified life of components within the scope of the program for license renewal. The continued implementation of the EQ program provides assurance that the aging effects will be managed and that components within the scope of the EQ program will continue to perform their intended functions for the period of extended operation.

4.4.3 UFSAR Supplement

LRA Section A.4.4 provides the UFSAR supplement summarizing the Environmental Qualification of Electric Components TLAA. The staff reviewed LRA Section A.4.4 consistent with the review procedures in SRP-LR Section 4.4.3.2, which states that the reviewer verifies that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.4.1.3. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the Environmental Qualification of Electric Components TLAA for the period of extended operation, as required by 10 CFR 54.21(d).

4.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of aging on the intended functions of the Environmental Qualification of Electric Components TLAA will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.5 Containment Liner Plate and Penetration Fatigue Analyses

4.5.1 Summary of Technical Information in the Application

LRA Section 4.5 describes the applicant's TLAA of the containment liner and penetrations fatigue analysis. The LRA states that the primary containment liner plate and anchorage system (welds and anchors) were analyzed for transient cycles caused by mechanical loads (MSRV discharge and chugging) to occur over 40 years. Stresses (primary, secondary membrane, and bending) were evaluated in accordance with ASME Code, Section III, Subsection NE-3222.2, and fatigue strength in accordance with ASME Code, Section III, Subsection NE-3222.4. Allowable design stress intensity values, design fatigue curves, and material properties used in the evaluation conform to ASME Code, Subsection NA, Appendix I. The LRA also states that the liner plate fatigue analysis has been identified as a TLAA.

The LRA further states that penetrations include the drywell head assembly, the equipment hatches, the personnel lock, the suppression chamber access hatches, the CRD removal hatch, and piping and electrical penetrations. The LRA also states that penetrations are designed per ASME Code Class MC steel components of the concrete containment since they form part of the pressure boundary not backed by structural concrete. A portion of each of the penetration sleeves extends beyond the containment wall. The entire length of any penetration sleeve is considered a Class MC component. The fatigue analyses for ASME Code Class MC components have been identified as TLAAs.

ASME Code Class 1 fatigue analyses were also performed for flued-head penetrations associated with the following piping systems: main steam, RCIC Steam, HPCI Steam, RHR supply and return, reactor water cleanup, standby liquid control (SLC), and LPCI injection. These fatigue analyses are based upon the same design transients as the ASME Code Class 1 piping systems they are associated with and have been identified as TLAAs.

LRA Tables 4.3.1-1 and 4.3.1-2 show the results of 60-year transient cycle projections. The applicant stated that the tables demonstrate that the 40-year transient cycle limits will not be exceeded in 60 years based upon the average rate of occurrence to-date. This includes startup and shutdown cycles and DBA events. The applicant further stated that an operational review was performed for the MSRV lift cycles that concluded the total number of cycles projected for 60 years, will not exceed the number analyzed for 40 years. Therefore, the analyses based upon these transients will remain valid for the period of extended operation.

The applicant dispositioned the TLAAs for the containment liner and containment penetrations in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the containment liner and penetrations fatigue analyses and the corresponding disposition of 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation, consistent with the review procedures in Section 4.6.3.1.1.1 of the SRP-LR. The SRP-LR states that the number of assumed transients used in the existing CUF calculations for the current operating term is compared to the extrapolation to 60 years of operation of the number of operating transients experienced to-date.

The staff reviewed LRA Section 4.5.1 for the containment liner and confirmed that UFSAR Section 3A.6.4, "Liner Plate Capability Assessment Criteria," states that stresses in the liner plate and anchorage system (welds and anchors) from mechanical loads such as SRV discharge and chugging are evaluated in accordance with ASME Code, Section III, Division 1, (1974). In addition the staff confirmed that UFSAR Section 3A.6.4 states that primary plus secondary membrane plus bending stresses are evaluated in accordance with ASME Code, Subsection NE-3222.2, "Primary-Plus-Secondary Stress Intensity," of the ASME Code of record. The staff also confirmed that the fatigue strength evaluation is based on Subsection NE-3222.4, "Analysis for Cyclic Operation," of the ASME Code of record. The staff confirmed that UFSAR Section 3A.6.4 states that allowable design stress intensity values, design fatigue curves, and material properties follow Subsection NA, Appendix I of the ASME Code of record.

The staff also reviewed UFSAR Section 3.8.2, "ASME Class MC Steel Components of the Containment" and confirmed that the concrete containment has the following ASME Class MC steel components: (1) drywell head assembly, (2) the equipment hatches, (3) the personnel lock, (4) the suppression chamber access hatches, (5) the CRD removal hatch, and (6) piping and electrical penetrations. The staff confirmed in UFSAR Section 3.8.2 that these components form a portion of the containment pressure boundary and are not backed by structural concrete. The staff then reviewed LRA Tables 4.3.1-1, "60-Year Transient Cycle Projections for LGS Unit 1," and 4.3.1-2, "60-Year Transient Cycle Projections for LGS Unit 2," of the LRA and confirmed that LGS Units 1 and 2 have limited the number of design cycles for startup to 120 cycles and shutdown to 120 cycles. For 60 years of operation the LRA tables indicate that the projected cycles are 112 startup transients and 109 shutdown transients for LGS Unit 1. The projected cycles for 60 years of operation are 90 startup transients and 88 shutdown transients for LGS Unit 2. The staff then confirmed per UFSAR Section 3.8.2.3.4, "Thermal Loads," that the ASME Class MC components are designed for startup and shutdown of 500 thermal cycles and for one DBA cycle. The staff also confirmed that UFSAR Sections 3.8.2.3, "Loads and Loading Combinations" and 3.8.2.4, "Design and Analysis Procedures," state that the ASME Code Class MC components include the effects of Mark II hydrodynamic load assessments caused by MSRV discharge and LOCA phenomena.

The staff then reviewed the UFSAR for flued-head penetrations for the following systems: main steam, RCIC steam, HPCI steam, RHR supply and return, reactor water cleanup, SLC, and LPCI injection. The staff confirmed that UFSAR Section 3.8.2.4.3, "Piping and Electrical Penetrations," states that Nuclear Class 1 design and analysis flued head penetrations comply with ASME Code Section III, Subsection B of the ASME Code of record. The staff also reviewed LRA Tables 4.3.1-1 and 4.3.1-2, which were evaluated in SER Section 4.3.1.2, and noted that cycle counting records from pre-operational startup testing through January 2011 indicate that projected transient cycles for 60 years of operation are less than the design cycle limits specified in UFSAR Section 5.6, "Component Cyclic or Transient Limit," of LGS Units 1 and 2, and in UFSAR Tables 3.9-2, "Design Events," and 5.2-9, "RCPB Operating Thermal Cycles."

The staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(i), that the analyses for the containment liner and penetrations fatigue analyses remain valid for the period of extended operation.

4.5.3 UFSAR Supplement

LRA Section A.4.5.1 provides the UFSAR supplement summarizing the containment liner and penetrations fatigue analyses. The staff reviewed LRA Section A.4.5.1 consistent with the review procedures in SRP-LR Section 4.6.3.2, which states that the number of assumed transients used in the existing CUF calculations for the current operating term should be compared to the extrapolation to 60 years of operation of the number of operating transients experienced to date. The comparison confirmed that the number of transients in the existing analyses would not be exceeded during the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.6.2.2 and SRP-LR Section 4.6.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of the fatigue design of the containment penetrations, as required by 10 CFR 54.21(d).

4.5.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the containment liner and penetrations fatigue analyses remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6 Other Plant-Specific TLAAs

LRA Section 4.6 summarizes the evaluation of the following plant-specific TLAAs:

- reactor enclosure crane cyclic loading analysis
- EDG enclosure
- RPV core plate rim hold-down bolt loss of preload
- main steam line flow restrictors erosion
- jet pump auxiliary spring wedge assembly
- jet pump restrainer bracket pad repair clamps
- refueling bellows and support cyclic
- downcomers and MSRV discharge piping
- jet pump slip joint repair clamps

Jet Pump Slip Joint Repair Clamps

4.6.1 Reactor Enclosure Crane Cyclic Loading Analysis

4.6.1.1 Summary of Technical Information in the Application

LRA Section 4.6.1 describes the applicant's TLAA for the reactor enclosure crane. The reactor enclosure crane is common to both units and was designed to meet the fatigue requirements of the Crane Manufacturers Association of America (CMAA) Specification 70 for a Class A, Standby or Infrequent Service Crane. The applicant stated that the evaluation of the reactor enclosure crane cyclic load limit TLAA included (1) reviewing the existing 40-year design basis to determine the number of load cycles considered in the design of the crane, (2) developing a 60-year projection for load cycles for the crane, and (3) comparing the 60-year projected number of cycles to the 40-year design cycles. The applicant further stated that the 60-year projected number of cycles is less than 20 percent of the minimum allowable design value of 20,000 cycles; therefore, the reactor enclosure crane load cycle fatigue analysis remains valid for 60 years of plant operation.

The applicant dispositioned the TLAA for the reactor enclosure crane in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.6.1.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the reactor enclosure crane and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which states that the existing analyses should be shown to be bounding during the period of extended operation. The SRP-LR also states that the applicant should describe the TLAA with respect to the objectives of the analysis, assumptions used in the analysis, conditions, acceptance criteria, relevant aging effects, and intended functions. The applicant should show that conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation, and acceptance criteria are maintained to provide reasonable assurance that the intended functions are maintained for renewal.

The staff reviewed LRA section 4.6.1, UFSAR Section 9.1.5, and CMAA Specification 70 and found that the reactor enclosure crane was designed to meet the fatigue requirements for a Class A, Standby or Infrequent Service Crane. The UFSAR states that the structural members of the reactor enclosure crane are designed for a fatigue loading of 20,000-100,000 cycles. The UFSAR further states that the reactor enclosure crane serves both units and is designed to be used normally during maintenance and refueling operations. LRA Table 4.6.1-1 shows the estimated total number of loading cycles for the 60-year projection, based on the existing 40-year design basis. The 60-year total load cycles is projected to be 3,468, which is less than 20 percent of the minimum design range of 20,000-100,000 cycles.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the reactor enclosure crane remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant's 60-year total load cycle projection showed that the existing analysis remains valid for the period of extended operation.

4.6.1.3 UFSAR Supplement

LRA Section A.4.6.1 provides the UFSAR supplement summarizing the reactor enclosure crane cyclic loading analysis. The staff reviewed LRA Section A.4.6.1 consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the applicant should provide information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA. SRP-LR Section 4.7.3.2 also states that each summary description is reviewed to verify that it is appropriate, such that later changes can be controlled by 10 CFR 50.59 and that the description should contain information that the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the reactor enclosure crane cyclic loading analysis, as required by 10 CFR 54.21(d).

4.6.1.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the reactor enclosure crane remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.2 Emergency Diesel Generator Enclosure Cranes

4.6.2.1 Summary of Technical Information in the Application

LRA Section 4.6.2 describes the applicant's TLAA for the EDG enclosure cranes. These eight EDG enclosure cranes were designed to meet or exceed the design fatigue requirements of CMAA Specification 70 for Class A, Standby or Infrequent Service Cranes. The applicant stated that the EDG enclosure cranes were evaluated for the period of extended operation by developing 60-year projections for crane load cycles and comparing these to the number of cycles evaluated for the design life of the cranes. The applicant also stated that a conservative estimate, as determined from review of station procedures and personnel knowledgeable on the use of these cranes, results in approximately 3,500 load cycles, which is less than 20 percent of the allowable design value of 20,000 cycles. Therefore, the analysis remains valid for the period of extended operation

The applicant dispositioned the TLAA for the emergency diesel generator enclosure cranes in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.6.2.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the EDG enclosure cranes and the corresponding disposition, consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which states that the existing analyses should be shown to be bounding even during the period of extended operation. The SRP-LR also states that the applicant describes the TLAA with respect to the objectives of the analysis, assumptions used in the analysis, conditions, acceptance criteria, relevant aging effects, and intended functions. The SRP-LR further states that the applicant shows that conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation, and acceptance criteria are maintained to provide reasonable assurance that the intended functions are maintained for renewal.

The staff reviewed LRA Section 4.6.2 and CMAA Specification 70 and found that the EDG enclosure cranes were designed to meet the fatigue requirements for a Class A, Standby or Infrequent Service Crane, which allows for a range of 20,000-100,000 load cycles. The applicant developed the 60-year projections for these cranes based on a review of station procedures and personnel knowledgeable on the use of these cranes. This estimate accounts for an estimated 500 load cycles during original construction and 50 load cycles per year during diesel generator maintenance. The total estimated 3,500 load cycles per crane, projected for 60 years, is less than 20 percent of the minimum design range of 20,000-100,000 cycles.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the emergency diesel generator enclosure cranes remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the applicant's 60-year total load cycle projection showed that the existing analysis remains valid for the period of extended operation.

4.6.2.3 UFSAR Supplement

LRA Section A.4.6.2 provides the UFSAR supplement summarizing the EDG enclosure cranes cyclic loading analysis. The staff reviewed LRA Section A.4.6.2 consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the applicant should provide information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA. SRP-LR Section 4.7.3.2 also states that each summary description is reviewed to verify that it is appropriate, such that later changes can be controlled by 10 CFR 50.59 and that the description should contain information that the TLAAs have been dispositioned for the period of extended operation.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the EDG enclosure cranes cyclic loading analysis, as required by 10 CFR 54.21(d).

4.6.2.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the EDG enclosure cranes remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.3 RPV Core Plate Rim Hold-down Bolt Loss of Preload

4.6.3.1 Summary of Technical Information in the Application

LRA Section 4.6.3 describes the applicant's loss of preload TLAA for the RPV core plate rim hold-down bolts. The RPV core plate is attached to the core support structure by stainless steel hold-down bolts that are preloaded during initial installation. These bolts are subject to stress relaxation (loss of preload) caused by irradiation effects. Since these bolts were evaluated for fluence expected to occur in 40 years, this analysis has been identified as a TLAA that requires evaluation for the period of extended operation.

The applicant dispositioned the TLAA for the RPV core plate rim hold-down bolts in accordance with 10 CFR 54.21(c)(1)(i), indicating that the analysis remains valid for the period of extended operation.

4.6.3.2 Staff Evaluation

The staff reviewed LRA Section 4.6.3 on the loss of preload TLAA for RPV core plate rim hold-down bolts, and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP–LR Section 4.7.3.1.1. The SRP–LR states that the staff should review the justification provided by the applicant to verify that the existing analyses are valid even during the period of extended operation.

LRA Section 4.6.3 states that a reduction in preload as high as 19 percent for these bolts is acceptable to meet the design requirements. In addition, an evaluation determined that the maximum relaxation value of 19 percent corresponds to an average fluence level of 8.0 E+19 n/cm^2. The staff noted that as long as the 60-year projected fluence level is less than 8.0 E+19 n/cm^2, than the original analysis remains valid. LRA Section 4.2.1 identifies that the EFPY at the end of 60 years of operation are 55 and 57 for LGS Units 1 and 2, respectively, but the applicant conservatively evaluated LGS Unit 1 for 57 EFPY for consistency with LGS Unit 2. The applicant stated in LRA Section 4.6.3 that it calculated the 57 EFPY fluence value using the RAMA fluence methodology. The staff noted that LRA Section 4.2.1 indicates that the high energy (>1 MeV) neutron fluence was calculated for the RPV beltline welds and shells using RAMA, which is consistent with RG 1.190. The staff's evaluation of the applicant's 57 EFPY fluence projections is documented in SER Section 4.2.1.2. The staff noted that the applicant calculated the 57 EFPY fluence value for the bolts by integrating along the length of the bolt. The resulting fluence value is 3.37 E+19 n/cm^2 for both the LGS Units 1 and 2 RPV core plate rim hold-down bolts. The staff noted that this calculated fluence value for the bolts is less than half of the original design value of 8.0 E+19 n/cm^2.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the loss of preload TLAA for the RPV core plate rim hold-down bolts analysis, remains valid for the period of extended operation. Additionally, the applicant's analysis meets the acceptance criteria in SRP–LR Section 4.7.2.1 because the projected 60-year fluence value, 3.37 E+19 n/cm^2, for the RPV core plate rim hold-down bolts does not exceed the 40-year allowed fluence value in the original design, 8.0 E+19 n/cm^2, with margin to account for unanticipated irradiation effects.

4.6.3.3 UFSAR Supplement

LRA Section A.4.6.3 provides the UFSAR supplement summarizing the loss of preload TLAA for the RPV core plate rim hold-down bolts. The staff reviewed LRA Section A.4.6.3, consistent with the review procedures in SRP–LR Section 4.7.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its analysis of the loss of preload TLAA for the RPV core plate rim hold-down bolts, as required by 10 CFR 54.21(d).

4.6.3.4 Conclusion

On the basis of its review the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the loss of preload TLAA for the RPV core plate rim hold-down bolts remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAA, as required by 10 CFR 54.21(d).

4.6.4 Main Steam Line Flow Restrictors Erosion

4.6.4.1 Summary of Technical Information in the Application

LRA Section 4.6.4 describes the applicant's TLAA of the main steam line flow restrictor erosion analysis for the stainless steel venturi-type nozzles welded into each main steam line pipe. The LRA states that, in response to a main steam line break outside of primary containment, the steam flow restrictors are designed to limit reactor coolant loss, to maintain core cooling, and to limit the release of radiological material to the environment. The LRA refers to UFSAR Section 5.4.4, which indicates that very slow erosion of the flow restrictors occurs with time, and that the resistance of stainless steel to erosion at similar steam velocities has been substantiated by turbine inspections at another BWR plant, which found no noticeable effects.

The LRA states calculations indicate that even with erosion rates as high as 0.004 inch per year, the increase in choked flow would be no more than 5 percent after 40 years of operation. The LRA also states that the steam line break analysis for LGS calculated an integrated mass of coolant leaving the reactor as 108,785 lbs, which is less than the bounding value of 140,000 lb used in the analysis as provided in SRP 15.6.4, Paragraph III.2.a for a GESSAR-251 plant. The LRA further states that postulating additional erosion, which would increase the choked flow rate 5 percent more, or a total increase of 10 percent, would not challenge the use of 140,000 lb coolant release as the bounding input to the dose calculation.

The applicant dispositioned the TLAA for the main steam line flow restrictor erosion analysis, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.6.4.2 Staff Evaluation

The staff reviewed LRA Section 4.6.4 and the Main Steam Line Flow Restrictor Erosion Analysis TLAA, to verify pursuant to 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation. The staff reviewed the applicant's TLAA for the main steam line flow restrictor erosion analysis and the corresponding disposition that the analysis remains valid for the period of extended operation, consistent with the review procedure in SRP-LR Section 4.7.3.1.1, which states that no reanalysis is necessary if (a) conditions and assumptions used in the analysis already address the relevant aging effects for the period of extended operation, and (b) acceptance criteria are maintained to provide reasonable assurance that the intended functions are maintained for renewal.

The staff reviewed the applicant's analysis as documented in UFSAR Section 5.4.4 and noted the large margin between the bounding assumption of 140,000 lbs total integrated mass leaving the reactor vessel through the steam line break and the calculated amount of 108,785 lbs in UFSAR Section 15.6.4, "Steam System Piping Break Outside of Primary Containment." The staff also noted the applicant had conservatively assumed that the additional erosion during the 20 years of extended operation would be the same amount as the first 40 years, which would result in an additional 5 percent increase, or a total of 10 percent above the calculated amount. The staff further noted that this conservative assumption would yield a total integrated mass leaving the reactor vessel of less than 120,000 lbs, which is still bounded by the original assumption of 140,000 lb.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the main steam line flow restrictor erosion remains valid for the period of extended operation. Additionally, the analysis meets the criteria of SRP-LR Section 4.7.3.1.1 because the bounding assumptions used in the original analysis will remain valid by assuming additional erosion during the next 20 years is the same amount assumed during the first 40 years, and no reanalysis is necessary.

4.6.4.3 UFSAR Supplement

LRA Section A.4.6.4 provides the UFSAR supplement summarizing the main steam line flow restrictor erosion analysis. The staff reviewed the LRA Section A.4.6.4 consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the information to be included in the UFSAR supplement should include a summary description of the evaluation of each TLAA.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.3.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the main steam line flow restrictor erosion analysis, as required by 10 CFR 54.21(d).

4.6.4.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54,21(c)(1)(i), that the analysis for the main steam flow restrictor erosion remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.5 Jet Pump Auxiliary Spring Wedge Assembly

4.6.5.1 Summary of Technical Information in the Application

LRA Section 4.6.5 describes the applicant's TLAA for the jet pump auxiliary spring wedge assemblies, which were designed and installed to maintain lateral support for the jet pump inlet mixer. The LRA states that the design analysis considered potential aging effects from fatigue usage and relaxation in preload caused by neutron fluence based on a 40-year design. The first assembly was installed in LGS Unit 1 in March 2004 and the first assembly was installed in LGS Unit 2 in March 2005.

Regarding fatigue usage, the LRA states that the jet pump auxiliary spring wedge assembly is not an ASME Code component; however, the ASME Code was used as a guideline to evaluate stress and fatigue limits. As such, the assembly was designed for cumulative fatigue usage for applicable Service Level B loads to be less than the allowable limit of 1.0. The LRA also states that the original design basis load cycles from the reactor vessel thermal cycle diagram were applied and these transients are the same as in UFSAR Table 3.9-2, "Plant Events." The resulting fatigue usage for the 40-year design was determined to be 0.77, which is below the allowable limit of 1.0. LRA Tables 4.3.1-1 and 4.3.1-2 show the 60-year transient projections for LGS and demonstrate that these transient cycle limits will not be exceeded in 60 years of operation.

Regarding relaxation in preload caused by neutron fluence, the LRA states that the original design analysis included an evaluation based on an integrated neutron fluence of 1.4 E+20 n/cm^2 for a 40-year design life. In order to evaluate relaxation in preload for the period of extended operation, fluence projections for the jet pump riser brace welds at the RS-9 locations were determined with the RAMA computer code. The LRA states that the fluence projections for the RS-9 weld locations bound projections for the auxiliary spring wedge assemblies, because the RS-9 welds are located at approximately the 304-inch elevation, while the auxiliary spring wedge assemblies are located at approximately the 230-inch elevation where fluence values are lower. The fluence projections through the period of extended operation were determined to be 1.30 E+20 n/cm^2 for LGS Unit 1 and 1.33 E+20 n/cm^2 for LGS Unit 2, which are both less than the 1.4 E+20 n/cm^2 fluence value used in the original design.

The applicant dispositioned the TLAA for the jet pump auxiliary spring wedge assemblies, in accordance with 10 CFR 54.21(c)(1)(i), indicating that the analysis remains valid for the period of extended operation.

4.6.5.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the jet pump auxiliary spring wedge assemblies and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which state that the existing analyses should be shown to be bounding during the period of extended operation.

Concerning fatigue usage, the applicant's analysis is based on its projections that the number of design cycles will not be exceeded during the period of extended operation. The applicant stated that the number of cycles used in the design of the auxiliary spring wedge assemblies is from UFSAR Table 3.9-2. LRA Section 4.6.5 states LRA Tables 4.3.1-1 and 4.3.1-2 show the 60-year transient projections and demonstrate that these transient cycle limits will not be exceeded in 60 years of operation. However, since this TLAA relies on 60-year projections that are dependent on the Fatigue Monitoring program (i.e., managing the number of cycles), the staff was not clear on the implications for cases in which the Fatigue Monitoring program may determine that a transient cycle count reaches a cycle limit. By letter dated November 18, 2011, the staff issued RAI B.3.1-1, requesting the applicant provide clarification.

In its response dated December 7, 2011, the applicant confirmed that the TLAA for the jet pump auxiliary spring wedge assembly is within scope of the Fatigue Monitoring program and based on the same set of design transients that this program monitors and trends. As such, the applicant confirmed that its procedures require its engineers to initiate corrective action to demonstrate the design limit will not be exceeded before or during the period of extended operation; otherwise, further action for repair or replacement of the component, or other methods approved by the staff will be taken. The staff determined in SER Section 3.0.3.2.20, that the applicant ensures that the results from its 60-year projections used to disposition the TLAA for RVI in accordance with 10 CFR 54.21(c)(1)(i), will remain valid during the period of extended operation, otherwise corrective actions will be taken.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA for the jet pump auxiliary spring wedge assembly based on fatigue, remain valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the projected number of transient cycles over the period of extended operation is not expected to exceed the design cycle limit used in the jet pump auxiliary spring wedge assembly fatigue analysis. The applicant also confirmed that this analysis is within the scope of the Fatigue Monitoring program, which ensures that the results from its projections used to disposition this fatigue TLAA will remain valid during the period of extended operation; otherwise, corrective actions will be taken.

Concerning relaxation in preload caused by neutron fluence, the applicant's analysis is based on demonstrating that the projected fluence values (using RAMA) at the RS-9 weld, which attaches the riser brace to the riser pipe and part of the jet pump assembly in the reactor vessel internals, bounds the fluence at the auxiliary spring wedge assemblies. The staff approved the use of RAMA for BWR pressure vessel fluence projections, but its use for reactor vessel internals applications is subject to staff's review on a case-by-case basis. Therefore, it was not clear why the use of RAMA is appropriate to project fluence at the RS-9 weld and why the fluence values at the auxiliary spring wedge assemblies would be lower than the fluence values at the RS-9 weld. By letter dated December 15, 2011, the staff issued RAI 4.6.5-1 requesting the applicant justify the use of RAMA for the RS-9 welds and why the fluence values at this location is bounding for the auxiliary spring wedge assemblies.

In its response dated January 24, 2012, the applicant stated that the staff evaluated use of RAMA for RPV and internal components of BWR plants in an SE dated May 13, 2005. The applicant indicated that the safety evaluation further states that, "if a licensee qualifies RAMA for calculating, for example, helium generation at one location (e.g., the core shroud), this qualifies RAMA for the same reactor and purpose at other reactor internals locations (e.g., the jet pumps)."

As documented in the NRC SE dated February 7, 2008, the staff reviewed EPRI Report 1011694, "BWR Vessel and Internals Project, Evaluation of Susquehanna Unit 2 Top Guide and Core Shroud Material Samples Using RAMA Fluence Methodology (BWRVIP-145)," dated November 2005, for its suitability in applying the RAMA fluence methodology to the calculation of fast neutron fluence values for BWR vessel internals, specifically the core shroud and top guide. The applicant highlighted a passage in the summary of this SE, which states that "the staff finds that for applications such as IASCC, crack propagation rates, and weldability determinations, the RAMA methodology can be used in determining fast neutron fluence values in the core shroud and top guide." The applicant also compared its case to that of Susquehanna Steam Electric Station (SSES) Unit 2. Specifically, LGS Units 1 and 2 are of the GE Type 4 BWR design, which is the same as SSES Unit 2, with 251-inch inside diameter reactors, 764 fuel bundles, and core shrouds with a 207-inch outside diameter. The applicant stated that since RAMA may be used at SSES Unit 2, for core shroud and top guide applications, it may also be used for the same applications at LGS Units 1 and 2.

The staff reviewed and addressed the applicant's use of RAMA methodology separately in Section 4.2.1.2 of this SER. The following evaluation covers the applicant's justification for the use of fluence projection at the RS-9 weld location to bound analysis for the jet pump auxiliary spring wedge assemblies.

The applicant stated in its response to RAI 4.6.5-1 dated January 24, 2012, that there are five jet pump welds located at different elevations in the reactor vessel. For each of these welds the applicant provided the associated elevation in the reactor vessel and the projected fluence values at 57 EFPY calculated using RAMA. The staff noted that the data show that the fluence decreases as elevation decreases below the 304-inch elevation where the RS-9 weld is located. The staff noted that the jet pump auxiliary spring wedge assemblies are located at the 230-inch elevation, which is in between the RS-9 weld and RS-2 weld; therefore, the staff finds that this data adequately demonstrates that fluence values at the RS-9 weld location will be higher than at the jet pump auxiliary spring wedge assemblies through 57 EFPY. Thus, use of the fluence at the RS-9 weld location is conservative for the jet pump auxiliary spring wedge assemblies.

The applicant also stated that the jet pump auxiliary spring wedge assemblies for LGS Units 1 and 2 were installed in March 2004 and March 2005, respectively. As a result, they will be exposed to fluence of 30 EFPY and 33.6 EFPY, respectively, through the period of extended operation. The applicant explained that the fluence values described in LRA Section 4.6.5 were derived from the 57 EFPY fluence values for the RS-9 weld by subtracting the fluence that had occurred before the installation dates. The staff finds the calculation of fluence values for the jet pump auxiliary spring wedge assemblies based on subtracting the fluence before installation of the assemblies from the fluence projected through 57 EFPY acceptable because the assemblies were not exposed to fluence before their installation. The staff noted that the fluence projections through the period of extended operation were determined to be 1.30 E+20 n/cm^2 for LGSUnit 1 and 1.33 E+20 n/cm^2 for LGS Unit 2. In addition, the applicant stated in its response that the fluence value used in the original design is 1.4 E+20 n/cm^2.

The staff finds the applicant's response acceptable, related to use of RAMA fluence methodology, because the fluence values used to demonstrate validity of the auxiliary spring wedge assemblies analysis are conservative, as described above, and these conservative fluence values are less than the fluence value used in the original design of these components. The staff's concerns described in RAI 4.6.5-1 are resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAA for the jet pump auxiliary spring wedge assemblies remain valid for the period of extended operation. Additionally, the analysis meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the fluence values for the jet pump auxiliary spring wedge assemblies at the end of the period of extended operation is less than the value used in the design specification for these components that analyzed relaxation of preload.

4.6.5.3 UFSAR Supplement

LRA Section A.4.6.5 provides the UFSAR supplement summarizing the TLAA for fatigue usage and relaxation in preload caused by neutron fluence of the jet pump auxiliary spring wedge assemblies. The staff reviewed LRA Section A.4.6.5 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue usage and relaxation in preload caused by neutron fluence of the jet pump auxiliary spring wedge assembly TLAAs, as required by 10 CFR 54.21(d).

4.6.5.4 Conclusion

On the basis of its review the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the jet pump auxiliary spring wedge assemblies remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.6 Jet Pump Restrainer Bracket Pad Repair Clamps

4.6.6.1 Summary of Technical Information in the Application

LRA Section 4.6.6 describes the applicant's TLAA for the jet pump restrainer bracket pad repair clamps. The LRA states that the repair clamps have been designed and installed to replace the support function of the restrainer bracket pad and end-of-life preload relaxation for 40 years was considered in the design analysis. The repair clamp uses four clamping bolts, which in order to maintain clamping under all operating conditions, must have a preload larger than the limiting lateral load of 2,059 lbs. In addition, the LRA states that fatigue was considered in the design analysis; however, the stress amplitude for cyclic loads was determined to be well below the ASME Code limit of 13,600 psi for 10^{11} cycles and less than the 10,000 psi limit for flow-induced vibration.

The applicant dispositioned the TLAA for the jet pump restrainer bracket pad repair clamps in accordance with 10 CFR 54.21(c)(1)(ii), indicating that the analysis has been projected to the end of the period of extended operation.

4.6.6.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the jet pump restrainer bracket pad repair clamps and the corresponding disposition of 10 CFR 54.21(c)(1)(ii), consistent with the review procedures in SRP-LR Section 4.7.3.1.2, which state that the results of the revised analysis should be reviewed to verify that their period of evaluation is extended, such that they are valid for the period of extended operation.

Loss of Preload

The applicant's analysis is based on the assumption that the preload will decrease 5 percent over an additional 20 years of operation, which is the same decrease predicted over the 40 years considered in the original design analysis; however, the LRA does not provide a justification for this assumption. By letter dated December 15, 2011, the staff issued RAI 4.6.6-1 requesting the applicant to justify this assumption.

In its response dated January 24, 2012, the applicant amended the LRA to provide a revised TLAA for the jet pump restrainer bracket pad repair clamps and changed the disposition to 10 CFR 54.21(c)(1)(i). For the revised TLAA, the applicant stated that a fluence value of 1.0 E+19 n/cm^2 was used in the design analysis to determine loss of preload, and this value is 5 percent higher than the 9.5 E+18 n/cm^2 value calculated for a 40-year service life. Therefore, the applicant concludes that the design analysis includes an allowance for loss of preload that is valid for 105 percent of 40 years (i.e., 42 years). The applicant stated that no clamps have been installed in LGS Unit 1 and the first clamps were installed in LGS Unit 2 in April 2009. Since the period of extended operation for LGS Unit 2 ends on June, 22, 2049, the applicant stated that the clamps will have a maximum service life of 40.25 years, which is less than 42 years.

The fluence value of 1.0 E+19 n/cm^2 used to determine the loss of preload and the calculated fluence value of 9.5 E+18 n/cm^2 for a 40-year service life were part of the original design analysis for the jet pump restrainer bracket pad repair clamps. The staff noted that in the design analysis the applicant used a larger fluence value to determine the loss of preload than was expected after a 40-year service life for these components. Thus, the staff finds it reasonable that the amount of time to accumulate the fluence used in the design analysis (1.0 E+19 n/cm^2) would be more than 40 years.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fluence TLAA for the jet pump restrainer bracket pad repair clamps remains valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the time needed to accumulate the fluence used in the design analysis to determine loss of preload (i.e., 42 years) is greater than the amount of time the pump auxiliary spring wedge assemblies will be in service through the period of extended operation (i.e., 40.25 years).

With respect to the applicant's calculation of the fluence projections, the staff's review of the applicant's use of the RAMA fluence methodology is documented in SER Section 4.2.1.2.

Fatigue

The applicant's analysis is based on the determination in the design that the stress amplitude for cyclic loads is below the ASME Code limit of 13,600 psi for 10^{11} cycles and less than the 10,000 psi limit for flow-induced vibration. The staff reviewed LRA Section 4.6.6 and noted that one disposition was provided, which states that the analysis has been projected to the end of the period of extended operation. However, for fatigue, it is not clear how the applicant projected the analysis because it did not describe the changes to any parameters of the original analysis. By letter dated December 15, 2011, the staff issued RAI 4.6.6-2 requesting the applicant to provide and justify the disposition for the fatigue portion of this TLAA.

In its response dated January 24, 2012, the applicant dispositioned the fatigue analysis under 10 CFR 54.21(c)(1)(i) and stated that the clamping loads do not cycle except for the load changes associated with startup and shutdown temperature changes. The largest alternating stress amplitude resulting from these temperature changes is 7,781 psi. In addition, the restrainer bracket is fabricated from Type 304 stainless steel, which has a stress intensity limit of 16,000 psi at 550 °F and yield strength of 17,750 psi at 550 °F. The applicant stated that the ASME Code stress limit is 13,600 psi for 10^{11} cycles and the GE Hitachi design limit for flow-induced vibration stress cycles is 10,000 psi. Thus, the applicant concluded that the fatigue usage will be insignificant since the cyclic loads of 7,781 psi are less than both of these limits.

The staff noted that a material exhibits an endurance limit in which fatigue damage is not expected to occur, which occurs when an alternating stress value is independent of the number of loading cycles. The staff finds the applicant's response acceptable because the applicant demonstrated that the alternating stresses in the jet pump restrainer bracket pad repair clamps are below the applicable endurance limits specified in the ASME Code and, therefore, fatigue damage will not occur. The staff's concern described in RAI 4.6.6-2 is resolved.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the fatigue TLAA for the jet pump restrainer bracket pad repair clamps remains valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.7.2.1 because the alternating stresses experienced by these components are less than the endurance limit specified in the ASME Code for this material and less than the design limit for flow-induced vibrations.

4.6.6.3 UFSAR Supplement

LRA Section A.4.6.6 provides the UFSAR supplement summarizing the TLAA for the jet pump restrainer bracket pad repair clamps. The staff reviewed LRA Section A.4.6.5 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

LRA Section A.4.6.6 provides the UFSAR supplement summary description for the TLAA evaluation of the jet pump restrainer bracket pad repair clamps described in LRA Section 4.6.6. However, a summary description for the analysis of fatigue was not provided. By letter dated December 15, 2011, the staff issued RAI 4.6.6-3 requesting the applicant to provide a summary description of the TLAA evaluation for fatigue of the jet pump restrainer bracket pad repair clamps in the UFSAR supplement.

In its response dated January 24, 2012, the applicant revised LRA Section A.4.6.6 to include a summary description of the TLAA evaluation for fatigue. The staff reviewed the revised LRA Section A.4.6.6 and finds it acceptable because it provides a summary description of the evaluation for fatigue consistent with the applicant's response to RAI 4.6.6-2. The staff's concern described in RAI 4.6.6-3 is resolved.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address loss of preload and fatigue of the jet pump restrainer bracket pad repair clamp TLAAs, as required by 10 CFR 54.21(d).

4.6.6.4 Conclusion

On the basis of its review the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analyses for the jet pump restrainer bracket pad repair clamps remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.7 Refueling Bellows and Support Cyclic Loading Analysis

4.6.7.1 Summary of Technical Information in the Application

LRA Section 4.6.7 describes the applicant's TLAA for the refueling bellows that provides a flexible seal to prevent leakage from the reactor well during refueling operations when it is flooded to permit fuel movement. The LRA states that the refueling bellows and refueling bellows support were analyzed for cycles predicted to bound 40 years of operation and that the fatigue analysis was identified as a TLAA that requires evaluation for 60 years. Since the refueling outages are scheduled once every 2 years, the 123 cycles will remain bounding for 60-years of operation. Furthermore, the LRA referred to section 4.3.1 that describes the applicant's TLAA for ASME Code, Section III, Class 1 fatigue analyses. 60-year transient projections were developed by using transient cycle monitoring data from the Fatigue Monitoring program. The projections show that the current design cycle limits will not be exceeded during 60 years of plant operation for LGS Unit 1 and LGS Unit 2. The Fatigue Monitoring program will also be used to monitor and track transient cycle occurrences through the end of the period of extended operations to ensure that these limits are not exceeded. The program includes requirements that trigger corrective action if a transient approaches a cycle limit.

The applicant dispositioned the TLAA for the refueling bellows and refueling bellows support in accordance with 10 CFR 54.21(c)(1)(i), that the analyses remain valid for the period of extended operation.

4.6.7.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the refueling bellows and refueling bellows support cyclic loading analysis and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedure in SRP–LR Section 4.7.3.1.1, which states that the existing analyses should be shown to be bounding even during the period of extended operation. In some instances, the applicant may identify activities to be performed to verify the assumption basis of the calculation, such as cycle counting.
LRA Section 4.3.1 states that the projections show that the current design cycle limits will not be exceeded during 60 years of plant operation for LGS Units 1 and 2; therefore, none of the transient types are expected to be exceeded during the period of extended operation and the ASME Code, Section III, Class 1 fatigue analyses will remain valid for the period of extended operation. The staff noted that since the applicant's assumption relies on the fact that the rate of cycle occurrence in the future will not exceed the average rates of occurrence of past cycles, the applicant trended each transient projection to determine if recent rates of occurrence could be higher than the overall average rates of occurrence. The applicant demonstrated, through such trending, that recent transient occurrence rates are bounded by the average occurrence rates. However, the staff noted that in order to assure that this conclusion and basis remains valid for transient projections and trending, the Fatigue Monitoring program will be used to monitor and track transient cycle occurrences through the end of the period of extended operation to ensure that these limits are not exceeded.

However, since this TLAA relies on the 60-year projections that the Fatigue Monitoring program is assuring will remain valid throughout the period of extended operation, it is not clear to the staff if the validity of this TLAA will be confirmed if the program determines that a transient cycle count reaches a cycle limit. By letter dated November 18, 2011, the staff issued RAI B.3.1-1, requesting the applicant provide clarification.

In its response dated December 7, 2011, the applicant confirmed that the refueling bellows TLAA is within the scope of the Fatigue Monitoring program and is based on the same set of design transients that this program monitors and trends. The applicant confirmed that its procedures require its engineers to initiate corrective action to demonstrate the design limit will not be exceeded before or during the period of extended operation; otherwise, further action for repair of the component, replacement of the component, or other methods approved by the NRC will be taken. The staff determined in SER Section 3.0.3.2.20, that the applicant continually ensures that the results from its 60-year projections used to disposition the refueling bellows TLAA in accordance with 10 CFR 54.21(c)(1)(i), will remain valid during the period of extended operation, otherwise corrective actions will be taken.

The staff finds the applicant has demonstrated, pursuant to 10 CFR 54.21(c)(1)(i), that the TLAA for the refueling bellows and refueling bellows support analyses based upon fatigue, remain valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.7.3.1.1 because the projected number of transient cycles over the period of extended operation is not expected to exceed the design cycle limits. The applicant also is crediting its Fatigue Monitoring program to assure that the assumptions in the Class 1 fatigue analyses remain valid during the period of extended operation; otherwise the applicant will take corrective actions in accordance with its program.

4.6.7.3 UFSAR Supplement

LRA Section A.4.6.7 provides the UFSAR supplement summarizing the refueling bellows and supports TLAA. The staff reviewed LRA Section A.4.6.7, consistent with the review procedures in SRP–LR Section 4.7.3.2, which states that the reviewer verifies that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of each TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP–LR Section 4.7.3.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to demonstrate that the refueling bellows and refueling bellows support 40-year cycle limits will not be exceeded in 60 years based on the average rate of occurrence to-date, as required by 10 CFR 54.21(d).

4.6.7.4 Conclusion

On the basis of its review the staff concludes that the applicant provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the refueling bellows and refueling bellows support remain valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.6.8 Downcomers and MSRV Discharge Piping

4.6.8.1 Summary of Technical Information in the Application

LRA Section 4.6.8 describes the applicant's fatigue TLAA for the downcomers and MSRV discharge piping. MSRV cycles were considered to account for the pool dynamic loads, which are based on 1,100 actuations of all MSRVs. In addition, the MSRV quenchers were analyzed for opening and closing cycles and irregular condensation load cycles. Since the piping and components were evaluated for transient cycles expected to occur in 40 years, these analyses have been identified as TLAAs that require evaluation for the period of extended operation. The applicant dispositioned the fatigue TLAA for the downcomers and MSRV discharge piping in accordance with 10 CFR 54.21(c)(1)(i) to demonstrate that the analysis remains valid for the period of extended operation.

4.6.8.2 Staff Evaluation

The staff reviewed LRA Section 4.6.8 and the fatigue TLAA for the downcomers and MSRV discharge piping and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3.1.1. The SRP-LR provides guidance for the staff to review the justification provided by the applicant to verify that the existing analyses are valid for the period of extended operation.

LRA Section 4.6.8 states that a minimum of 7,700 MSRV cycles were considered to account for the pool dynamic loads. In addition, for the most frequently actuated MSRVs, the analysis was based on three stress cycles per each of the 4,700 actuations (14,100 total cycles). The LRA states the total number of MSRV lift cycles has been projected, and it will not exceed the number analyzed for 40 years. The applicant did not provide its current accumulated number of MSRV cycles or the 60-year projected number of MSRV cycles; therefore, the staff could not verify the adequacy of the applicant's TLAA disposition. The staff reviewed LRA Tables 4.3.1-1 and 4.3.1-2 and could not determine the transient associated with the MSRV cycle. By letter dated January 31, 2012, the staff issued RAI 4.6.8-1 requesting the applicant to identify the transients used in the fatigue analysis for the downcomers, including the current accumulated number and 60-year projected number for each transient.

In its response dated February 29, 2012, the applicant stated that two types of loads were considered in the fatigue evaluation of the downcomers and bracing: (1) seismic effects and cyclic loads caused by hydrodynamic effects, including MSRV actuations; and (2) LOCA-related condensation oscillation and chugging cycles. These components were analyzed for a minimum of 7,700 MSRV stress cycles to account for the pool hydrodynamic loads, which was based on seven stress cycles per each of the 1,100 actuations. The applicant also stated that these components were also evaluated for 3,000 chugging cycles that occur following a LOCA event, 50 operational basis earthquakes (OBE) cycles (5 events with 10 stress cycles per event), and 10 safe-shutdown earthquakes (SSE) cycles (1 event with 10 cycles). The staff confirmed that UFSAR Figure 3A-394 indicates that the cycles associated with chugging, OBEs, and SSEs are included in the fatigue analysis for the downcomers.

Based on its review, the staff finds the applicant's response to this portion of RAI 4.6.8-1 acceptable because the applicant identified all the transients used as an input to the fatigue analysis of the downcomers and bracing, which will be monitored by the Fatigue Monitoring program to ensure that these fatigue analyses remain valid during the period of extended operation.

Also, in its response to RAI 4.6.8-1, the applicant addressed the historical cycle accumulation and future cycle projection for the transients discussed above. The applicant stated that MSRV actuation cycles were not monitored since original plant startup and an operational review during the development of the LRA was performed to determine when each MSRV was actuated. The applicant stated that it reviewed surveillance tests that actuated MSRVs, monthly operating reports that documented operational MSRV actuations, and the fatigue monitoring data for other events that resulted in MSRV actuations.

Based on a review of its operating history, the applicant determined that the cumulative number of MSRV actuations for LGS Unit 1 through January 2011 was 90 (56 actuations during startup testing before commercial operation, 30 actuations caused by surveillance testing performed following the first 6 refueling outages, and 4 actuations during normal operation). The applicant's surveillance test required each of the five automatic depressurization system ADS valves to be opened once during each startup after a refueling outage; however, the applicant stated that this surveillance test requirement was eliminated in 1997. The applicant stated the 60-year projection for LGS Unit 1 MSRV actuations is 211, which is based upon a linear extrapolation of the MSRV actuation data using the average rate of occurrence through January 2011. Similarly, the applicant determined the cumulative number of MSRV actuations for LGS Unit 2 through January 2011 was 49 (32 actuations during startup testing before commercial operation, 15 caused by surveillance testing following the first three refueling outages before1997, and 2 actuations during normal operation). Similar to LGS Unit 1, the surveillance test for LGS Unit 2 was also eliminated. The 60-year projection for LGS Unit 2 MSRV actuations is 138, which is based on a linear extrapolation of the MSRV actuation data using the average rate of occurrence through January 2011.

The applicant stated that LOCA-related loads include condensation oscillation and 3,000 chugging cycles that account for pulsating condensation of the steam flow exiting the downcomers. The staff noted that UFSAR 3A.7.1.1.1.1.5.2 explains that the main LOCA-related forcing functions are the condensation oscillation and chugging cycles. Thus, the staff finds it reasonable that the applicant monitors the occurrence of the LOCA event to account for the condensation oscillation and chugging cycles. The applicant monitors Transient No. 18, "Faulted Condition – Pipe Rupture and Blowdown," which corresponds with a large-break LOCA. The applicant also stated that no such event has occurred in either unit and that its records also show that no OBE or SSE event has occurred. The applicant stated that since there have been no occurrences for these transients, the design limits of one LOCA-related event, one OBE event, and one SSE event in LRA Tables 4.3.1-1 and 4.3.1-2 are not projected to be exceeded in 60 years for LGS Units 1 or 2.

The staff finds the applicant's estimated number of accumulated cycles through January 2011 for MSRV actuation to be reasonable because it is based on pre-operational and surveillance tests, which are no longer performed. In addition, the use of a linear extrapolation is conservative because the applicant considered the time period when it experienced frequent transient occurrences and did not consider only the time period when it discontinued the surveillance test. The staff noted that the number of cycles through the period of extended operation for both units is expected to be no more than 20 percent of the 1,100 allowable cycle limit; therefore, there is a significant margin to account for unanticipated cycles of the MSRV actuations through the period of extended operation.

Based on its review, the staff finds this portion of the applicant's response to RAI 4.6.8-1 acceptable because the past occurrences for the transients used in these fatigue analyses were reconciled based on documented operating data and records and the applicant's 60-year projections are conservative, as described above.

In its response to RAI 4.6.8-1, the applicant also revised LRA Tables 4.3.1-1 and 4.3.1-2 to include Transient No. 20, "MSRV Actuations," with a limit of 1,100 MSRV actuations. In addition, these tables were also revised to include the monitoring results for the faulted condition events already monitored by the Fatigue Monitoring program, which include Transient No. 18, "Pipe Rupture and Blowdown," and Transient No. 19, "Safe Shutdown Earthquake at Rated Operating Conditions." The applicant further explained that since the Fatigue Monitoring program monitors each of the transients analyzed for the downcomers, or in the case of condensation oscillation and chugging cycles, it monitors correlated LOCA events, the disposition of the fatigue TLAA for the downcomers in LRA Section 4.6.8 and UFSAR supplement Section A.4.6.8 is revised from 10 CFR 54.21(c)(1)(i) to 10 CFR 54.21(c)(1)(iii). The staff's review of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the fatigue analysis.

Based on its review, the staff finds this portion of the applicant's response to RAI 4.6.8-1 acceptable because the applicant's TLAA credits the Fatigue Monitoring program to monitor the transients assumed in the analysis, thus, ensuring that the MSRV downcomers fatigue analysis remains valid during the period of extended operation. The staff's concerns described in RAI 4.6.8-1 are resolved.

LRA Section 4.6.8 states the quenchers were analyzed for 7,000 SRV opening and closing cycles and LOCA-related irregular condensation load cycles. The applicant did not provide the accumulated and 60-year projected numbers for the SRV cycles and irregular condensation load cycles; therefore, the staff cannot verify the adequacy of the TLAA disposition in accordance with 10 CFR 54.21(c)(1)(i). The staff reviewed LRA Tables 4.3.1-1 and 4.3.1-2 and could not determine the transients associated with these two transient cycles.

By letter dated January 31, 2012, the staff issued RAI 4.6.8-2 requesting the applicant to identify the transients used in the fatigue analysis for the MSRV discharge piping and quenchers, including the accumulated number and 60-year projected number for each transient.
In its response dated February 29, 2012, the applicant stated that two types of loads were considered in the fatigue evaluations, which include thermal and pressure transients and cyclic loads (i.e., MSRV actuations, LOCA-related condensation oscillation and chugging, and seismic effects). The applicant stated that the thermal transients used in the fatigue analysis include those identified in LRA Tables 4.3.1-1 and 4.3.1-2. The staff reviewed UFSAR Section 3A.7.1.5.1.1 and confirmed that these transients were used in the fatigue evaluations for the MSRV discharge piping and quenchers.

The applicant also stated that the MSRV discharge loads include a minimum of 7,700 MSRV stress cycles to account for the pool hydrodynamic loads, which is based on 1,100 actuations of all MSRVs. The LOCA-related loads include condensation oscillation loads and 3,000 chugging cycles. The seismic loads include 50 OBE cycles (5 events with 10 stress cycles per event), and 10 SSE cycles (1 event with 10 cycles). The applicant stated that the quenchers at the ends of the MSRV discharge lines were analyzed for 7,000 MSRV actuations and one million irregular condensation cycles. Based on its review, the staff finds this portion of the applicant's response acceptable because the applicant identified all the transients used in the fatigue analyses of the MSRV discharge piping and quenchers and the Fatigue Monitoring program monitors these transients to ensure these fatigue analyses will remain valid during the period of extended operation.

In its response to RAI 4.6.8-2, the applicant also addressed the historical cycle accumulation and future cycle projection for these transients. The applicant stated that the thermal transients described previously other than MSRV actuations have been monitored since original plant startup, as shown in LRA Tables 4.3.1-1 and 4.3.1-2. As discussed in the response to RAI 4.6.8-1, MSRV actuation cycles were not monitored since original plant startup and an operational review during development of the LRA was performed to determine when each MSRV was actuated during preoperational startup testing and during all past plant operations for each unit. The 60-year projections of the MSRV actuation are 211 for LGS Unit 1 and 138 for LGS Unit 2, and the projection methodology is also discussed in the response to RAI 4.6.8-1. The staff's review of the applicant's estimate of the historical occurrences and future projections are documented in the review of RAI 4.6.8-1. The staff noted that the number of cycles through the period of extended operation for both units is expected to be no more than 20 percent of the

1,100 allowable cycles; therefore, there is a significant margin to account for unanticipated cycles of the MSRV actuations.

The applicant further stated that it does not directly monitor chugging cycles or irregular condensation cycles. Rather, it monitors Transient No. 18, "Faulted Condition – Pipe Rupture and Blowdown," which corresponds with a large-break LOCA. UFSAR Section 3B.4.1.3.5 explained that the LOCA-related forcing function on the quenchers consists of 1,000,000 irregular condensation cycles. Thus, the staff finds it reasonable that the applicant monitors the occurrence of the LOCA event instead of 1,000,000 irregular condensation cycles. The applicant stated no LOCA event has occurred in either unit and records also show that no OBE or SSE event has occurred. Since no transients that cause chugging and irregular condensation cycles have occurred to-date in either unit, the staff finds it reasonable to conclude that no chugging and irregular condensation cycle have occurred either. The applicant stated that since there has been zero occurrences for these transients, the design limits of one LOCA-related event, one OBE event and one SSE event in LRA Tables 4.3.1-1 and 4.3.1-2 are not projected to be exceeded in 60 years for LGS Units 1 or 2.

Based on its review, the staff finds this portion of the applicant's response to RAI 4.6.8-2 acceptable because the past occurrences for the transients used in these fatigue analyses were reconciled based on documented operating data and records and the applicant's 60-year projections are conservative, as described above.

Finally, in its response to RAI 4.6.8-2, the applicant revised LRA Tables 4.3.1-1 and 4.3.1-2 to include Transient No. 20, "MSRV Actuations." The disposition of the MSRV discharge piping and quenchers fatigue TLAA in LRA Section 4.6.8 and UFSAR supplement Section A.4.6.8 is also revised from 10 CFR 54.21(c)(1)(i) to 10 CFR 54.21(c)(1)(iii), crediting the Fatigue Monitoring program for managing the effects of fatigue. The staff's review of the Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the fatigue analysis.

Based on its review, the staff finds the remainder of the applicant's response to RAI 4.6.8-2, acceptable because the applicant credits the Fatigue Monitoring program to monitor the transients assumed in the analysis, thus, ensuring the validity of the MSRV discharge piping and quenchers fatigue analysis during the period of extended operation. The staff's concerns described in RAI 4.6.8-2 are resolved.

The staff determined that the Fatigue Monitoring program monitors and tracks the number of critical thermal, pressure, and seismic transients to ensure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the fatigue analysis. The staff noted that the program requires comparison of the actual event parameters to the applicable design transient definitions to ensure that the actual transients are bounded by the applicable design transients. If a transient approaches an action limit, which the applicant has set to 80 percent of the cycle limit, corrective actions are initiated for repair, replacement, or reanalysis of the component, in accordance with its Fatigue Monitoring program. The staff determined that these characteristics of the Fatigue Monitoring program are consistent with GALL Report AMP X.M1.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue of the downcomers and MSRV discharge piping will be adequately managed for the period of extended operation. Additionally, the applicant has met the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because it is crediting its Fatigue Monitoring program, which the staff has determined is consistent with GALL Report AMP X.M1, to manage metal fatigue by ensuring the assumptions in these fatigue analyses remain valid for the period of extended operation.

4.6.8.3 UFSAR Supplement

LRA Section A.4.6.8, as amended by letter dated February 29, 2012, provides the UFSAR supplement summarizing the fatigue TLAA for the downcomers and MSRV discharge piping. The staff reviewed LRA Section A.4.6.8, consistent with the review procedures in SRP-LR Section 4.7.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.7.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the fatigue TLAA for the downcomers and MSRV discharge piping, as required by 10 CFR 54.21(d).

4.6.8.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that effects of fatigue for the downcomers and MSRV discharge piping will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAA, as required by 10 CFR 54.21(d).

4.6.9 Jet Pump Slip Joint Repair Clamps

4.6.9.1 Summary of Technical Information in the Application

LRA Section 4.6.9 describes the applicant's TLAA for the jet pump slip joint repair clamps. The LRA states that the repair clamps minimize vibration and wear of the jet pump assemblies by applying a lateral preload to the slip joint between the exit end of the inlet-mixer and the entrance end of the diffuser. The LRA states that the jet pumps and repair hardware will be periodically inspected under the BWR Vessel Internals program and aging effects included within the scope of these inspections include cracking, wear, and bolt loosening. As such, the loss of preload will be managed during the period of extended operation.

The applicant dispositioned the TLAA for the jet pump slip joint repair clamps in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of loss of preload caused by neutron fluence on the intended functions will be adequately managed by the BWR Vessel Internals program for the period of extended operation.

4.6.9.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the jet pump slip joint repair clamps and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.7.3.1.3, which state that the applicant's AMP should be reviewed to verify that the effects of aging on the intended function(s) are adequately managed consistent with the CLB for the period of extended operation.

The jet pump slip joint repair clamps are subject to a loss of preload caused by neutron fluence and the LRA states that this loss of preload will be managed through periodic inspections under the BWR Vessel Internals program. The staff reviewed GALL Report AMP XI.M9 and found that it does not manage loss of preload; therefore, it is not clear how the applicant's program will manage this aging effect. By letter dated December 15, 2011, the staff issued RAI 4.6.9-1 requesting the applicant to provide the specific details as to how the BWR Vessels Internals program manages loss of preload.

In its response dated January 24, 2012, the applicant stated that it re-evaluated the TLAA and determined that the existing design analysis remains valid through the period of extended operation because the fluence value used to determine loss of preload will not be exceeded. The applicant revised the disposition of the TLAA to 10 CFR 54.21(c)(1)(i) and stated that RAMA fluence projections were prepared to determine the maximum fluence received during the service life for these slip joint clamps. Furthermore, since the core shroud is closer to the reactor core than the jet pumps, the applicant stated that the peak fluence received on the outer surface of the core shroud is less than the fluence at the same elevation on the jet pumps, caused by the extra shielding provided by the reactor coolant in the space between the shroud and the jet pumps.

As such, the applicant stated that the peak fluence on the outer surface of the core shroud at the 207.3-inch elevation of the slip joint clamps was used to provide a conservative estimate of the fluence at the highest point on the slip repair joint clamps. The resulting fluence projections are 1.24 E+18 n/cm^2 and 1.28 E+18 n/cm^2 for the slip joint repair clamps of LGS Units 1 and 2, respectively. The staff finds it conservative that the applicant used the fluence values for the core shroud in its evaluation of the fluence values for the jet pump slip joint repair clamps because the core shroud is closer to the reactor core than the jet pumps. In addition, the staff finds it reasonable that the peak fluence received on the outer surface of the core shroud is less than the fluence at the same elevation on the jet pumps because of the extra shielding from the reactor coolant in the space between the core shroud and the jet pumps.

The staff finds the applicant's response acceptable because the projected fluence values for these components are less than the fluence value used in the design specification for the structural evaluation of the repair clamps that analyzed loss of preload. In addition, as described above, the staff finds the values used by the applicant to demonstrate that the jet pump slip joint repair clamps remains valid for the period of extended operation to be reasonable. The staff's concern described in RAI 4.6.9-1 is resolved.

With respect to the applicant's calculation of the fluence projections, the staff's review of the applicant's use of the RAMA fluence methodology is documented in SER Section 4.2.1.2.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(i), that the TLAA for the jet pump restrainer pad repair clamps remains valid for the period of extended operation. Additionally, the applicant meets the acceptance criteria in SRP-LR Section 4.7.3.1.1

because the fluence value for the jet pump restrainer pad repair clamps at the end of the period of extended operation is less than the design value used in the design specification for the structural evaluation of the repair clamps that analyzed loss of preload.

4.6.9.3 UFSAR Supplement

LRA Section A.4.6.9 provides the UFSAR supplement summarizing the TLAA for loss of preload of the jet pump slip joint repair clamps. The staff reviewed LRA Section A.4.6.9 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, as amended by letter dated January 24, 2012, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.2.2 and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address loss of preload of the jet pump slip joint repair clamps, as required by 10 CFR 54.21(d).

4.6.9.4 Conclusion

On the basis of its review the staff concludes that the applicant has provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(i), that the analysis for the jet pump slip joint repair clamps remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.10 Fuel Pool Girder Loss of Prestress

4.6.10.1 Summary of Technical Information in the Application

During its review the staff noted that the prestressed concrete girders that provide the main support for the LGS Units 1 and 2 spent fuel pools use grouted tendons. Since the tendons are grouted, conventional inspection procedures (e.g., lift-off tests to indicate the level of prestressing force) used to evaluate the structural integrity of ungrouted tendon systems cannot be used. The continued presence of elevated temperatures, creep and shrinkage of the concrete, and relaxation of the prestressing tendon steel could, through losses of prestressing force, produce increased deflections of the girders and have a negative effect on associated safety-related SCs. Increased deflections also can lead to cracking of the concrete that may impact the structural integrity of the prestressed girders (e.g., provide access for environments that may cause corrosion of the tendon steel) and the spent fuel pools. Therefore, by letter dated January 30, 2012 the staff issued RAI B.2.1.35-1 requesting the applicant to provide a plant-specific TLAA or a plant-specific inspection/monitoring program to provide assurances that the capability of the prestressed concrete girders associated with the spent fuel pool will continue to meet their intended function(s) during the period of extended operation.

By letter dated February 28, 2012, the applicant responded to RAI B.2.1.35-1 and added LRA Section 4.6.10, which describes the applicant's TLAA for the loss of prestress associated with the post-tensioned concrete fuel pool girders. The revised LRA states that "[t]he original design analysis for the fuel pool girders evaluated loss of prestress caused by stress relaxation of the steel tendons, caused by creep and shrinkage of the concrete, and other factors. Since stress relaxation of the steel tendons is based upon a time-limited assumption, this analysis has been identified as a TLAA that requires evaluation for the period of extended operation."

The applicant stated that stress relaxation of the steel tendons was based on stress relaxation values obtained from three tests and projected to girder life of 114 years, which bound the extended service life of approximately 71 years from the construction of the girder until the end of the period of extended operation. The applicant also stated that there are several other factors that contribute to loss of prestress; however, these losses were accounted for by assigning an overall reduction in prestress during the design phase and are considered bounding for the life of the component.

The applicant dispositioned the TLAA for the fuel pool girder in accordance with 10 CFR 54.21(c)(1)(i), that the analysis remains valid for the period of extended operation.

4.6.10.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the fuel pool girders and the corresponding disposition of 10 CFR 54.21(c)(1)(i), consistent with the review procedures in SRP-LR Section 4.7.3.1.1, which state that the staff should verify that the existing analyses are valid and bounding for the period of extended operation.

The staff reviewed the applicant's TLAA, as well as its response to RAI B.2.1.35-1, and noted that the majority of prestressing losses were either accounted for during the design of the girders or are not time-dependent. Creep and shrinkage losses are both time-dependent; however, they reach limiting values either before the application of postensioning (shrinkage) or immediately after the initial loading (creep). Creep was accounted for during the design of the girders and is considered bounding for the life of the component. The time-dependent loss that continues throughout the life of the component is the stress relaxation of the steel tendons, which is estimated to be four percent and is accounted for in the original girder prestress design. This four percent loss value was based on testing and corresponds to 1,000,000 hours, or approximately 114 years of operation. Since the design uses a value associated with 114 years, which is greater than the approximately 71-year service life at the end of the period of extended operation, the staff finds the applicant has demonstrated pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the fuel pool girder remains valid for the period of extended operation. Additionally, it meets the acceptance criteria in SRP-LR Section 4.7.3.1.1 because the analysis remains valid and the original analysis bounds the service life of the girders at the end of the period of extended operation.

In addition, the applicant has included the fuel pool girders within the scope of the Structures Monitoring program, which means they will be visually inspected for cracking, deflections, and indications of corrosion on a 5-year frequency. Additional discussion on the aging management of the fuel pool girders can be found in the staff's review of the Structures Monitoring program, SER Section 3.0.3.2.17.

4.6.10.3 UFSAR Supplement

By letter dated February 28, 2012, in response to RAI B.2.1.35-1, the applicant added LRA Section A.4.6.10, which provides the UFSAR supplement summarizing the fuel pool girder loss of prestress TLAA associated with the post-tensioned concrete fuel pool girders. The staff reviewed LRA Section A.4.6.10 consistent with the review procedures in SRP-LR Section 4.7.3.2, which state that the staff should verify that the summary description in the UFSAR supplement should contain appropriate information, including the TLAA disposition.

Based on its review of the UFSAR supplement, the staff finds it meets the acceptance criteria in SRP-LR Section 4.7.3.2, and is, therefore, acceptable. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the post-tensioned concrete fuel pool girder prestress losses caused by tendon relaxation, as required by 10 CFR 54.21(d).

4.6.10.4 Conclusion

On the basis of its review, the staff concludes that the applicant has provided an acceptable demonstration, pursuant to 10 CFR 54.21(c)(1)(i), that the analysis for the post-tensioned concrete fuel pool girders remains valid for the period of extended operation. The staff also concludes that the UFSAR supplement contains an appropriate summary description of the TLAA evaluation, as required by 10 CFR 54.21(d).

4.6.11 RHR and Core Spray Suction Strainer Fatigue Analyses

4.6.11.1 Summary of Technical Information in the Application

By letter dated March 13, 2012, in response to RAI 3.2.2.1.1-1, the applicant added LRA Section 4.6.11, which describes the applicant's TLAA for RHR and CS suction strainer. The LRA states that the original RHR and CS suction strainers were replaced with larger passive strainer designs. The design stress analyses for the replacement strainers include fatigue analyses for the stainless steel bolting and strainer assemblies; therefore, these fatigue analyses have been identified as TLAAs that require evaluation for 60 years.

The applicant dispositioned the TLAA for RHR and CS suction strainer in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on the intended functions of the RHR and CS suction strainer bodies and bolting will be managed by the Fatigue Monitoring program for the period of extended operation.

4.6.11.2 Staff Evaluation

The staff reviewed the applicant's TLAA for the RHR and CS suction strainers and the corresponding disposition of 10 CFR 54.21(c)(1)(iii), consistent with the review procedures in SRP-LR Section 4.3.3.1.1.3, which states that the staff should verify that the applicant has identified the appropriate program as described and evaluated in the GALL Report and includes an assessment of the TLAA information against relevant design basis and CLB information.

In its response dated March 13, 2012, to RAI 3.2.2.1.1-1 regarding the staff's separate review of bolting in engineered safety feature (ESF) systems, the applicant determined that the RHR and CS suction strainer stress analysis includes fatigue analyses for the stainless steel bolting materials and for the stainless steel strainer assembly. The staff's review of RAI 3.2.2.1.1-1 is documented in SER Section 3.2.2.1. Consistent with identification of these TLAAs, the following LRA sections were added by the applicant: LRA Section 4.6.11, "RHR and Core Spray Strainer Fatigue Analyses," and Appendix A, Section A.4.6.11, "RHR and Core Spray Strainer Fatigue Analyses."

LRA Section 4.6.11 states that the replacement RHR and CS suction strainers were designed in accordance with ASME Code Section III and included fatigue analyses of the stainless steel bolting and strainer assembly, with resulting fatigue usage values less than 1.0. Specifically, these analyses were based upon 34,200 MSRV stress cycles (11,400 actuations),10 SSE stress cycles (1 event), 50 OBE cycles (5 events) and condensation oscillation and chugging cycles that would result from LOCA events. The applicant stated that these are the same types of transients analyzed for the downcomers, as described in revised LRA Section 4.6.8 which was provided in the response to RAI 4.6.8-1, by letter dated February 29, 2012.

The applicant's response to RAI 4.6.8-1 amended LRA Tables 4.3.1-1 and 4.3.1-2 to include the following transients:

- Transient No. 18 – Faulted Condition – Pipe Rupture and Blowdown (1,000 psig to 35 psig in 15 seconds)
- Transient No. 19 – Faulted Condition – Safe Shutdown Earthquake at Rated Operating Conditions
- Transient No. 20 – Main Steam Relief Valve Actuations

As discussed in the applicant's responses to RAIs 4.3-2 and 4.6.8-1, condensation oscillation and chugging cycles are the result of a LOCA, which corresponds to Transient No. 18. The staff noted that the 50 OBE cycles were already included in LRA Tables 4.3.1-1 and 4.3.1-2 as Transient No. 8a. Therefore, the staff finds that the Fatigue Monitoring program, as amended by letter dated February 29, 2012, is monitoring and tracking the transients used in the fatigue analyses of the RHR and CS suction strainers.

The staff's review of the applicant's Fatigue Monitoring program is documented in SER Section 3.0.3.2.20. The staff determined that the program monitors and tracks the number of critical thermal, pressure, and seismic transients to assure that the cumulative number of occurrences of each transient type is maintained below the number of cycles used in the most limiting ASME Code Class 1 fatigue analysis. In addition, the program requires comparison of the actual event parameters to the applicable design transient definitions to ensure that the actual transients are bounded by the applicable design transients. If a transient approaches an action limit, which the applicant has set to 80 percent of the cycle limit, corrective actions are initiated for repair, replacement, or reanalysis of the component, in accordance with its Fatigue Monitoring program. The staff determined that these characteristics of the applicant's Fatigue Monitoring program are consistent with GALL Report AMP X.M1. The staff noted that the applicant's method for managing these fatigue analyses is conservative because corrective actions are initiated when one transient type approaches 80 percent of the cycle limit, when typically a fatigue analysis includes more than one transient type.

The staff finds the applicant has demonstrated, in accordance with 10 CFR 54.21(c)(1)(iii), that the effects of fatigue on RHR and CS suction strainers will be adequately managed for the period of extended operation. Additionally, the applicant's TLAA meets the acceptance criteria in SRP-LR Section 4.3.2.1.1.3 because the applicant's Fatigue Monitoring program monitors the transient severity and tracks the number of design basis transients that will occur through the period of extended operation, and includes action limits and corrective actions that will ensure that the assumption made in the fatigue analyses for the RHR and CS suction strainer components will not be exceeded during the period of extended operation.

4.6.11.3 UFSAR Supplement

By letter dated March 13, 2012, in response to RAI 3.2.2.1.1-1, the applicant added LRA Section A.4.6.11, which provides the UFSAR supplement summarizing the TLAA for the RHR and CS suction strainers. The staff reviewed LRA Section A.4.6.11, consistent with the review procedure in SRP-LR Section 4.3.3.2, which states that the reviewer should verify that the applicant has provided information to be included in the UFSAR supplement that includes a summary description of the evaluation of the TLAA.

Based on its review of the UFSAR supplement, the staff finds that the supplement meets the acceptance criteria in SRP-LR Section 4.3.2.2. Additionally, the staff determines that the applicant provided an adequate summary description of its actions to address the TLAA of the RHR and CS suction strainers, as required by 10 CFR 54.21(d).

4.6.11.4 Conclusion

On the basis of its review, the staff concludes that the applicant provided an acceptable demonstration, in accordance with 10 CFR 54.21(c)(1)(iii), that effects of fatigue for the RHR and CS suction strainers components will be adequately managed for the period of extended operation. The staff also concludes that the UFSAR supplement contains an adequate summary description of the evaluated TLAAs, as required by 10 CFR 54.21(d).

4.7 Conclusion for TLAAs

The staff reviewed the information in LRA Section 4, "Time-Limited Aging Analyses." On the basis of its review, the staff concludes that the applicant has provided a sufficient list of TLAAs, as defined in 10 CFR 54.3 and that the applicant has demonstrated that: (1) the TLAAs remain valid for the period of extended operation, as required by 10 CFR 54.21(c)(1)(i); (2) the TLAAs have been projected to the end of the period of extended operation, as required by 10 CFR 54.21(c)(1)(ii); or (3) that the effects of aging on the intended function(s) will be adequately managed for the period of extended operation, as required by 10 CFR 54.21(c)(1)(iii). The staff also reviewed the UFSAR supplement for the TLAAs and finds that the supplement contains descriptions of the TLAAs sufficient to satisfy the requirements of 10 CFR 54.21(d). In addition, the staff concludes that two plant-specific, TLAA-based exemptions are in effect and that the applicant has provided an adequate evaluation that justifies the continuation of these exemptions for the period of extended operation, as required by 10 CFR 54.21(c)(2).

With regard to these matters, the staff concludes that there is reasonable assurance that the activities authorized by the renewed licenses will continue to be conducted in accordance with the CLB, and that any changes made to the CLB, in order to comply with 10 CFR 54.29(a), are in accordance with the Atomic Energy Act of 1954, as amended, and NRC regulations.

SECTION 5

REVIEW BY THE ADVISORY COMMITTEE ON REACTOR SAFEGUARDS

In accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) Part 54, the Advisory Committee on Reactor Safeguards (ACRS) will review the license renewal application (LRA) for Limerick Generating Station (LGS), Units 1 and 2. The ACRS Subcommittee on Plant License Renewal will continue its detailed review of the LRA after this safety evaluation report (SER) is issued. Exelon Generation Company, LLC (Exelon) and the staff of the United States (US) Nuclear Regulatory Commission (NRC) (the staff) will meet with the Subcommittee and the full Committee to discuss issues associated with the review of the LRA.

After the ACRS completes its review of the LRA and SER, the full Committee will issue a report discussing the results of the review. An update to this SER will include the ACRS report and the staff's response to any issues and concerns reported.

SECTION 6

CONCLUSION

The staff of the United States Nuclear Regulatory Commission (NRC, the staff) reviewed the license renewal application (LRA) for the Limerick Generating Station (LGS), Units 1 and 2, in accordance with NRC regulations and NUREG-1800, Revision 1, "Standard Review Plan for Review of License Renewal Applications for Nuclear Power Plants," dated December 2010. The standards for issuance of a renewed license are in accordance with Title 10 of the *Code of Federal Regulations* (10 CFR) 54.29, "Requirements for Renewal of Operating Licenses for Nuclear Power Plants."

On the basis of its review of the LRA, the staff determines that the requirements of 10 CFR 54.29(a) have been met.

The staff noted that any requirements of 10 CFR Part 51, Subpart A, will be documented in a Draft supplement to NUREG-1437, "Generic Environmental Impact Statement for License Renewal of Nuclear Plants (GEIS)."

APPENDIX A

LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS

During the review of the Limerick Generation Station (LGS), Units 1 and 2 license renewal application (LRA) by the staff of the United States (U.S.) Nuclear Regulatory Commission (NRC) (the staff), Exelon Generation Company, LLC (Exelon or the applicant) made commitments related to aging management programs (AMPs) to manage aging effects for structures and components. The following table lists 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 ASME Code 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: 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				
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: 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. 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. 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. 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				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
11	Bolting Integrity is an existing program that will be enhanced to: 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. 2. Prohibit the use of lubricants containing molybdenum disulfide for closure bolting for pressure retaining components. 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. 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				
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: 1. Perform internal inspection of buried safety-related service water piping when it is accessible during maintenance and repair activities. 2. Perform periodic inspections for loss of material in the nonsafety-related service water system at a minimum of five locations on each unit once every refueling cycle. 3. Replace the supply and return piping for the core spray pump compartment unit coolers. 4. Replace degraded RHRSW piping in the pipe tunnel. 5. Perform periodic inspections for loss of material in the safety-related service water system at a minimum of 10 locations every 2 years.	A.2.1.12	Program to be enhanced before the period of extended operation. Inspection schedule as identified in the commitment.	Letters dated February 15, and June 22, 2012

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 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. 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) non-regenerative 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. Inspection schedule as identified in the commitment.	Letter dated February 15, 2012

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 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. 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. 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. 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: 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

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
17	Fire Protection is an existing program that will be enhanced to: 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. 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
18	Fire Water System is an existing program that will be enhanced to: 1. Replace sprinkler heads or perform 50-year sprinkler head testing using the guidance of NFPA 25 "Standard for the Inspection, Testing and Maintenance of Water-Based Fire Protection Systems" (2002 Edition), Section 5.3.1.1.1. This testing will be performed before the 50-year inservice date and every 10 years thereafter. 2. Inspect selected portions of the water based fire protection system piping located aboveground and exposed to the fire water internal environment by non-intrusive volumetric examinations. These inspections shall be performed before the period of extended operation and will be performed every 10 years thereafter.	A.2.1.18	Program to be enhanced before the period of extended operation.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 1. Include 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. 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 before 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.	A.2.1.19	Program to be enhanced before the period of extended operation. Inspection schedule as identified in the commitment.	Letter dated February 12, 2012

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 1. Periodically drain water from the fire pump engine diesel oil day tank and the fire pump diesel engine fuel tank. 2. Perform internal inspections of the fire pump engine diesel oil day tank, the fire pump diesel engine fuel tank, and the diesel generator day tanks, at least once during the 10-year period 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. 3. Perform periodic analysis for total particulate concentration and microbiological organisms for the fire pump engine diesel oil day tank and the fire pump diesel engine fuel tank. 4. Perform periodic analysis for water and sediment and microbiological organisms for the diesel generator diesel oil storage tanks. 5. Perform periodic analysis for water and sediment content, total particulate concentration, and the levels of microbiological organisms for the diesel generator day tanks. 6. Perform analysis of new fuel oil for water and sediment content, total particulate concentration and the levels of microbiological organisms for the fire pump engine diesel oil day tank and the fire pump diesel engine fuel tank. 7. Perform analysis of new fuel oil for total particulate concentration and the levels of microbiological organisms for the diesel generator diesel oil storage tanks.	A.2.1.20	Program to be enhanced before the period of extended operation. Inspection schedule as described in the commitment.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
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. One-time inspections will be performed within the 10 years before the period of extended operation.	LRA
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. 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. One-time inspections will be performed within the 6 years before the period of extended operation.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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	A.2.1.25	Program to be implemented before the period of extended operation.	LRA
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.	A.2.1.26	Program to be implemented before the period of extended operation.	LRA
27	Existing Lubricating Oil Analysis is credited.	A.2.1.27	Ongoing	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 1. Perform test coupon analysis on a 10-year frequency, beginning no earlier than 2020 for Unit 1 and 2021 for Unit 2. 2. Initiate corrective action if coupon test result data indicates that acceptance criteria will be exceeded before the next scheduled test coupon analysis. 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). 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. Inspection schedule as described in the commitment.	Letter dated April 27, 2012

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 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, the inspection sample size is again doubled. This doubling of the inspection sample size continues as necessary. 2. Coat the underground emergency diesel generator system fuel oil piping before the period of extended operation. The coating will be in accordance with Table 1 of NACE SP0169-2007 or Section 3.4 of NACE RP0285-2002. 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 before the entry into the period of extended operation. Before 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 qualified inspector.	A.2.1.29	Program to be enhanced before the period of extended operation. Inspection schedule as described in the commitment.	Letter dated March 30, 2012

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
29 (cont.)	4. Perform two sets of volumetric inspections of the safety-related service water 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 service water system piping and components in the underground vault or a minimum of 10 feet of the linear length of in scope safety-related service water system piping and components in the underground vault. Inspection locations will be selected based on susceptibility to degradation and consequences of failure. 5. Specify that visual inspections of safety-related service water system underground piping and components will be performed by a NACE qualified inspector. 6. Perform trending of the cathodic protection testing results to identify changes in the effectiveness of the system and to ensure that the rectifiers required to protect in scope piping are reliable 90 percent of the time. 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 or copper sulfate electrode, an issue report will be entered into the corrective action program.			

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
30	ASME Code Section XI, Subsection IWE is an existing program that will be enhanced to: 1. Manage the suppression pool liner and coating system to: a. Remove any accumulated sludge in the suppression pool every refueling outage. b. Perform an ASME IWE examination of the submerged portion of the suppression pool each ISI period. 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 (PEO): • • 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. • 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 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,	A.2.1.30	Program to be enhanced before the period of extended operation. Inspection schedule as described in the commitment.	Letter dated October 25, 2012

Item	Commitment	UFSAR Supplement Section/ LRA Section	Enhancement or Implementation Schedule	Source
	Subsection IWE, Category E-C. • 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. d. Use the results of the ASME IWE examination to implement a coating maintenance plan to perform the following during the PEO: • 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. • 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. • For plates with greater than 25 percent coating depletion, the affected area will be recoated no later than the next scheduled inspection.			

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
	The coating maintenance plan will continue through the period of extended operation to ensure the coating protects the liner to avoid significant material loss. 2. Use the results of the ASME IWE inspection of the submerged portions of the suppression pool downcomers to perform the following:. • 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. • 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. 3. When IWE examinations are conducted, perform ultrasonic thickness measurements on four areas of submerged suppression pool liner affected by general corrosion. 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.			

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
31	ASME Code Section XI, Subsection IWL is an existing program that will be enhanced to: 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 Code Section XI, Subsection IWF is an existing program that will be enhanced to: 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
34	Masonry Walls is an existing program that will be enhanced to: 1. Add the following structures with masonry walls to the program scope: *a.* administration building warehouse *b.* fuel oil pumphouse *c.* transformer foundation dike walls 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. 3. Require an inspection frequency of not greater than 5 years. 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. Inspection schedule as described in the commitment.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
35	Structures Monitoring is an existing program that will be enhanced to: 1. Add the following structures: a. admin building warehouse b. fuel oil pumphouse c. service water pipe tunnel d. yard structures • aux fire water storage tank foundation • backup fire pump house and foundation • well pump #3 enclosure and foundation • railroad bridge • manholes 001 and 002 • fuel oil storage tank dike • transformer foundations and dikes 2. Add the following components and commodities: a. pipe, electrical, and equipment component support members b. pipe whip restraints and jet impingement shields c. panels, racks, and other enclosures d. sliding surfaces e. sump and pool liners f. electrical cable trays and conduits g. electrical duct banks h. tube tracks	A.2.1.35	Program to be enhanced before the period of extended operation. Inspection schedule as described in the commitment.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
35 (cont.)	i. doors j. penetration seals k. blowout panels l. permanent drywell shielding m. roof scuppers 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. 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 (RSCS) Specification for Structural Joints Using High Strength Bolts, Section 2.0. 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. 6. Perform inspections on a frequency not to exceed 5 years. 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			

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
35 (cont.)	water. 8. Require that personnel performing inspections and evaluations meet the qualifications specified within ACI 349.3R. 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. 10. Monitor accessible sliding surfaces to detect significant loss of material caused by wear, corrosion, debris, or dirt, which could result in lock-up or reduced movement. 11. Perform opportunistic inspection of below grade portions of in-scope structures in the event of excavation that exposes normally inaccessible below grade concrete. 12. Include applicable acceptance criteria from ACI 349.3R. 13. Clarify that loose bolts and nuts and cracked high-strength bolts are not acceptable unless accepted by engineering evaluations.			

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
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: 1. Require inspection of structural bolting integrity (loss of material and loosening of the bolts). 2. Require monitoring of aging effects for increase of porosity and permeability of concrete structures and loss of material for steel components. 3. Require the proper functioning of dike drainage systems. 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. 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. 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. 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 aging management program should be implemented to manage the concrete aging during the period of extended operation.	A.2.1.36	Program to be enhanced before the period of extended operation. Inspection schedule as described in the commitment.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
36 (cont.)	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. 9. Require acceptance and evaluation of structural concrete using quantitative criteria based on Chapter 5 of ACI 349.3R. 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 (RSCS) 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: 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
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 to be enhanced before the period of extended operation. Inspection schedule as described in the commitment.	LRA

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
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. 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. Assessment schedule identified in commitment.	LRA
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. 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. Periodic actions will be taken to prevent inaccessible cables from being exposed to significant moisture. Manholes associated with the cables included in this aging management program 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 operating experience 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. Test and Inspection schedule identified in commitment.	Letter dated February 28, 2012

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
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 percent with a maximum sample size of 25) of the accessible metal enclosed bus bolted connection population will be tested using thermography. 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. Test and inspection schedule identified in commitment.	LRA
42	Fuse Holders aging management program is a new program that applies to fuse holders located outside of active devices that have been identified as susceptible to aging effects. 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. 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 does not occur 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: 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

APPENDIX A: LIMERICK GENERATING STATION, UNITS 1 AND 2 LICENSE RENEWAL COMMITMENTS				
Item	**Commitment**	**UFSAR Supplement Section/ LRA Section**	**Enhancement or Implementation Schedule**	**Source**
45	Existing Environmental Qualification (EQ) of Electric Components program is credited.	A.3.1.2	Ongoing	LRA
46	The Operating Experience program is an existing program that will be enhanced to: 1. Explicitly require the review of operating experience for aging-related degradation. 2. Establish criteria to define aging-related degradation. 3. Establish identification coding for use in identification, trending, and communications of aging-related degradation. 4. Require communication of significant internal aging-related degradation, associated with SSCs 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. 5. Require review of external operating experience for information related to aging management, and evaluation of such information for potential improvements to LGS aging management activities. 6. Provide training to those responsible for screening, evaluating and communicating operating experience items related to aging management.	A.1.6	Program to be enhanced no later than the date that the renewed operating licenses are issued..	Letter dated 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 Code 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 United States (U.S.) Nuclear Regulatory Commission (NRC) (the staff) and Exelon Generation Company, LLC (Exelon). This appendix also lists other correspondence on the staff's review of the Limerick Generating Station (LGS) license renewal application (LRA) (under Docket Nos. 50-352 and 50-353).

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Date	**Subject**
June 22, 2011	Letter from Gallagher M., Exelon Generation Co., LLC, to U.S. NRC Document Control Desk, "Limerick Generating Station, Units 1 and 2 - Application for Renewed Operating Licenses." (ADAMS Accession No. ML11179A096)
June 22, 2011	Exelon Generation Co., LLC. "Limerick Generating Station, Units 1 & 2 - License Renewal Application." (ADAMS Accession No. ML11179A101)
June 22, 2011	Exelon Generation Co., LLC. "Limerick Generating Station, Units 1 and 2 - Applicant's Environmental Report Operating License Renewal Stage." (ADAMS Accession No. ML11179A104)
June 22, 2011	Exelon Generation Co., LLC, "Limerick Generating Station License Renewal Application Boundary Drawings." (ADAMS Accession No. ML12009A107)
July 13, 2011	Letter from Holian, B. E., U.S. NRC, to Gallagher, M., Exelon Generation Co., LLC, "Receipt and Availability of the License Renewal Application for the Limerick Generating Station Units 1 and 2." (ADAMS Accession No. ML11180A040)
July 13, 2011	Federal Register Notice, "Notice of Availability of the LRA for the Limerick Generating." (ADAMS Accession No. ML11180A178)
August 12, 2011	Letter from Holian B. E., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Determination of Acceptability and Sufficiency for Docketing, Proposed Review Schedule, and Opportunity for a Hearing Regarding the Application from Exelon Generation Company, LLC for Renewal of the Operating Licenses for Limerick Generating Station." (ADAMS Accession No. ML11206A206)
September 6, 2011	"Notice of Forthcoming Meeting to Discuss the License Renewal Process and Environmental Scoping for Limerick Generating Station, Units 1 And 2, License Renewal Application." (ADAMS Accession No. ML11245A008)
September 15, 2011	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Plan for the Scoping and Screening Regulatory Audit Regarding the Limerick Generating Station, Units 1 and 2 License Renewal Application Review (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11255A032)

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Date	**Subject**
September 20, 2011	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Plan for the Aging Management Program Regulatory Audit Regarding the Limerick Generating Station, Units 1 and 2 License Renewal Application Review." (ADAMS Accession No. ML11258A109)
November 18, 2011	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station License Renewal Application." (ADAMS Accession No. ML11308A001)
December 7, 2011	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2, Response to NRC Request for Additional Information, Dated November 18, 2011." (ADAMS Accession No. ML113410144)
December 9, 2011	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Scoping and Screening Methodology Audit Report Regarding the Limerick Generating Station, Units 1 and 2 (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11342A205)
December 15, 2011	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station License Renewal Application (TAC ME6555, ME6556)." (ADAMS Accession No. ML11343A438)
January 5, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "RAI for the Review of the Limerick Generating Station License Renewal Application (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11335A317)
January 17, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station License Renewal Application (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11347A360)
January 18, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11361A083)
January 24, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11361A079)
January 24, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 & 2 - Response to NRC Request for Additional Information, dated December 15, 2011, Related to License Renewal Application." (ADAMS Accession No. ML12024A507)
January 27, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, U.S. NRC Document Control Desk, "Limerick, Units 1 and 2, Response to NRC Request for Information, Dated January 5, 2012, Related to License Renewal Application." (ADAMS Accession No. ML12027A228)

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Date	**Subject**
January 30, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556)." (ADAMS Accession No. ML11364A099)
January 31, 2012	Letter from Kuntz R. F., 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, ME6556) TLAA 43 and 468 RAIs." (ADAMS Accession No. ML12005A251)
February 14, 2012	Letter from Kuntz R. F., 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, ME6556) RAPB AMR2 RAIs." (ADAMS Accession No. ML12018A033)
February 15, 2012	Letter from Gallagher M., Exelon Generation Co, LLC Exelon Nuclear, NRC/Document Control Desk, "Response to NRC RAI dated Jan. 17, 2012 re: Limerick Gen. Station LRA." (ADAMS Accession No. ML120470084)
February 16, 2012	Letter from Kuntz R. F., 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. ML12017A159)
February 16, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555 and ME6556) OE and Other RAIs." (ADAMS Accession No. ML12024A231)
February 16, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2 - Response to NRC Request for Additional Information, dated January 17, 2012." (ADAMS Accession No. ML120470372)
February 17, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC ME6555 and ME6556)." (ADAMS Accession No. ML12019A156)
February 23, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests for Addtional Information for the Review of the Limerick Generating Station, Units 1 & 2, License Renewal Application (TAC ME6555 and ME6556)." (ADAMS Accession No. ML12018A035)
February 28, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 & 2, Response to NRC Request for Additional Information, dated January 30, 2012, Related to License Renewal Application." (ADAMS Accession No. ML12059A345)
February 28, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Aging Management Programs Audit Report Regarding the Limerick Generating Station, Units 1 and 2 (TAC Nos. ME6555 and ME6556)" (ADAMS Accession No. ML12018A332)

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Date	**Subject**
February 29, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, U.S. NRC Document Control Desk, "Limerick, Units 1 and 2 - Response to NRC Request for Additional Information, dated January 31, 2012 Related to License Renewal Application." (ADAMS Accession No. ML12060A154)
March 5, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, U.S. NRC Document Control Desk, "Limerick, Units 1 and 2 - Response to NRC Requests for Additional Information, dated February 16, 2012, and February 17, 2012, Related to Renewal Application." (ADAMS Accession No. ML12065A206)
March 9, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "Summary of the Telephone Conference Call Held on December 14, 2011, Between the U.S. Nuclear Regulatory Commission and Exelon on Generation Company, LLC, Concerning Requests For Additional Information Pertaining to the Limerick 12-14-11 Telecon Summary." (ADAMS Accession No. ML12009A135)
March 9, 2012	Letter from Kuntz R. F., 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) Limerick App. J RAIs." (ADAMS Accession No. ML12046A899)
March 13, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, U.S. NRC Document Control Desk, "Response to NRC Requests for Additional Information, dated February 14 and February 16, 2012, Related to the Limerick Generating Station License Renewal Application." (ADAMS Accession No. ML120730361)
March 20, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2, Response to NRC Requests for Additional Information, dated February 23 and March 9, 2012, Related to License Renewal Application." (ADAMS Accession No. ML12080A118)
March 22, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Letter re: Request for Additional Information for the Review of the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC Nos. ME6555, ME6556) Buried Piping and FP Follow Up." (ADAMS Accession No. ML12074A037)
March 27, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick Generating Station, Units 1 and 2 - Response to NRC Request for Additional Information, dated February 28th, 2012, related to the License Renewal Application." (ADAMS Accession No. ML12088A366)
March 30, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2 - Response to NRC Request for Additional Information, dated March 22, 2012 and Information Addressing Minor Errors or Omissions Related to License Renewal Application." (ADAMS Accession No. ML12090A489)
April 5, 2012	Letter from Kuntz R. F., 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) BWR SCC SMP and CTWS follow up." (ADAMS Accession No. ML12080A190)

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Date	**Subject**
April 9, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "February 9, 2012, Summary of Telephone Conference Call Held Between the U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Request For Additional Information Pertaining to the Limerick." (ADAMS Accession No. ML12066A026)
April 11, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "February 23, 2012, Summary of Telephone Conference Call Held on February 23, 2012, 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 Application (ADAMS Accession No. ML12083A211)
April 13, 2012	Letter from Kuntz R. F., 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. ME6556 and ME6555) Fluence and FP Followup RAIs." (ADAMS Accession No. ML12089A377)
April 13, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2, Response to NRC Requests for Additional Information, dated April 5, 2012, Related to License Renewal Application." (ADAMS Accession No. ML12104A118)
April 16, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests 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. ML12082A155)
April 17, 2012	Letter from Kuntz R. F., 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)TLAA Followup RAIs." (ADAMS Accession No. ML12095A398)
April 20, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "Summary of Telephone Conference Call Held on January 18, 2012, Between The U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Request for Additional Information Pertaining to the Limerick Generation 1-18-12 Telecon Summary." (ADAMS Accession No. ML12025A051)
April 20, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "February 17, 2012, Summary of Telephone Conference Call Held between U.S. Nuclear Regulatory Commission and Exelon Generation Company, LLC, Concerning Request for Additional Information Pertaining to the Limerick 2-17-12 Telecon Summary." (ADAMS Accession No. ML12059A080)
April 26, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "1/12/2012 Telecon Summary 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 Application." (ADAMS Accession No. ML12018A023)
April 27, 2012	Letter from Gallagher M., Exelon Generation Co, LLC Exelon Nuclear, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2 - Response to NRC Requests for Additional Information, dated April 13 and April 16, 2012, related to the License Renewal Application." (ADAMS Accession No. ML12121A009)

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Date	**Subject**
April 30, 2012	Letter from Kuntz R. F., 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) SCC RAIs." (ADAMS Accession No. ML12111A034)
May 1, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "02/14/2012 Summary of Telephone Conference Call Held between NRC and Exelon Generation Co., LLC, Concerning Requests for Additional Information Pertaining to the Limerick, License Renewal Application (TAC ME6555 and ME6556)." (ADAMS Accession No. ML12047A124)
May 4, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2, Responses to NRC Requests for Additional Information, dated April 17, 2012, Related to the License Renewal Application." (ADAMS Accession No. ML12125A334)
May 7, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S NRC Document Control Desk, "Limerick, Units 1 and 2, Responses to NRC Requests for Additional Information, Dated April 30, 2012, Related to the License Renewal Application." (ADAMS Accession No. ML12128A438)
May 18, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "RAI for Review of the Limerick Generation Station, Units 1 & 2 & License Renewal Application." (ADAMS Accession No. ML12123A092)
May 18, 2012	Letter from Kuntz R. F., 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, (TAC Nos. ME6555 AND ME6556) Scoping Drawings Followup RAI." (ADAMS Accession No. ML12136A036)
May 24, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "4-17-12 Telecon Summary." (ADAMS Accession No. ML12115A281)
May 31, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk, "Limerick, Units 1 and 2, Responses to NRC Requests for Additional Information, dated May 18, 2012, Related to the License Renewal Application." (ADAMS Accession No. ML12152A309)
June 5, 2012	Letter from Kuntz R. F., U.S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Requests 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. ML12143A028)
June 7, 2012	Meeting Summary from Kuntz R. F., U. S. NRC, "4-30-12 Telecon Summary." (ADAMS Accession No. ML12139A066)
June 8, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk NRC/NRR, "Limerick, Units 1 and 2, Response to NRC Request for Additional Information, dated May 18, 2012, Related to License Renewal Application." (ADAMS Accession No. ML12160A553)

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Date	**Subject**
June 12, 2012	Letter from Kuntz R. F., 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. ML12152A305)
June 12, 2012	Letter from Kuntz R. F., 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) OpE Followup RAI." (ADAMS Accession No. ML12157A212)
June 12, 2012	Letter from Kuntz R. F., U. S. NRC, to Gallagher M., Exelon Generation Co., LLC, "LGS RWCU Followup 2 RAI." (ADAMS Accession No. ML12160A012)
June 14, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk NRC/NRR, "Limerick, Units 1 and 2, Response to NRC Request for Additional Information, dated June 5, 2012, Related to License Renewal Application." (ADAMS Accession No. ML12166A286)
June 14, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk NRC/NRR; "Limerick, Units 1 and 2, 10 CFR 54.21(b) Annual Amendment to License Renewal Application." (ADAMS Accession No. ML12166A325)
June 19, 2012	Letter from Gallagher M., Exelon Generation Co, LLC, to U.S. NRC Document Control Desk NRC/NRR, "Limerick, Units 1 and 2, Responses to NRC Requests for Additional Information, dated June 12, 2012, Related to the Limerick Generating Sation License Renewal Application." (ADAMS Accession No. ML12171A487)
June 21 2012	Letter from Kuntz R. F., 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) OCCW followup RAI." (ADAMS Accession No. ML12171A035)
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Date	**Subject**
July 16, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "Summary of Telephone Conference Call held on January 4, 2012 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 Application (TAC Nos. ME6555 and ME6556)." (ADAMS Accession No. ML12018A087)
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July 20, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "4/12/12 Telecon Summary with Exelon Generation Company, LLC." (ADAMS Accession No. ML12139A071)
July 20, 2012	Meeting Summary from Kuntz R. F., U.S. NRC, "4/5/12 Telecon Summary with Exelon Generation Company, LLC." (ADAMS Accession No. ML12139A074)
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October 10, 2012	Letter from Milano, P. D., U. S. NRC, to Gallagher M., Exelon Generation Co., LLC, "Request for Additional Information for the Limerick Generating Station, Units 1 and 2, License Renewal Application (TAC No. ME6555 and ME6556)." (ADAMS Accession No. ML12283A096)
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Date	**Subject**
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APPENDIX C

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

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APPENDIX D

REFERENCES

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

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